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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)

Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	End of 2013/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	End of 2013/Q4

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
6100 Neil Rd, Reno, NV 89511

05 Name of Contact Person	06 Title of Contact Person
E. Kevin Bethel	Sr VP&Chief Financial Officer

07 Address of Contact Person *(Street, City, State, Zip Code)*
6226 West Sahara Avenue, Las Vegas, NV 89146

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(702) 402-5622	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
/s/ E. Kevin Bethel		
02 Title		
Sr VP and Chief Financial Officer	/s/ E. Kevin Bethel	04/21/2014

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

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

☒ Two copies will be submitted

☐ No annual report to stockholders is prepared

GENERAL INFORMATION

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

E. Kevin Bethel, Chief Financial Officer
6100 Neil Road
Reno, Nevada 89511

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

State of Nevada
Incorporated January 15, 1965

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

Not Applicable

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

Generation, distribution and sales of electric energy in the state of Nevada. Distribution of natural gas in the state of Nevada.

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

(1) ☐ Yes...Enter the date when such independent accountant was initially engaged:
(2) ☒ No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

CONTROL OVER RESPONDENT

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

NV Energy, Inc. owns 100% of Sierra Pacific Power Company's common stock.

NVE Holdings, LLC owns 100% of NV Energy, Inc. common stock.

MidAmerican Energy Holdings Company owns 100% of the membership interests of NVE Holdings, LLC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Pinon Pine Investment Corp	Investment in LLP	100	
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3	Pinon Pine Corp	Investment in LLP	100	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Current Officers		
2	Chief Executive Officer	Michael W. Yackira	900,000
3	President	Paul J. Caudill	400,000
4	Senior VP and Chief Financial Officer	E. Kevin Bethel	275,000
5	Senior VP, Government and Community Strategy	Tony F. Sanchez, III	343,462
6	Senior VP, Customer Operations	Patrick S. Egan	235,000
7	Senior VP, General Counsel, Corporate Secretaary and	Douglas A. Cannon	190,000
8	Chief Compliance Officer		
9	Treasurer and Executive, Financial Strategies	Mohammed N. Mughal	220,000
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11	Other Executive Officers in 2013		
12	Exec. VP, Finance, Chief Financial Officer	Jonathan S. Halkyard	382,135
13	Exec. VP, General Counsel, Shared Services & Sec.	Paul J. Kaleta	496,577
14	Exec. VP, & Chief Operatiing Officer	Dilek L. Samil	500,000
15	Sr. VP, Energy Delivery	Roberto R. Denis	404,359
16	Sr. VP, Customer Relationship	Robert E. Stewart	330,196
17	Sr. VP, Human Resources and	Alice A. Cobb	371,154
18	Information Technology & Telecom		
19	VP, Energy Supply	Kevin C. Geraghty	270,000
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Schedule Page: 104 Line No.: 1 Column: c

All salaries consist of annual base salary only.

Schedule Page: 104 Line No.: 3 Column: b

Mr. Caudill was elected December 19, 2013. For additional information regarding Mr. Caudill refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 4 Column: b

Mr. Bethel was elected December 19, 2013. For additional information regarding Mr. Bethel refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 5 Column: b

Mr. Sanchez was elected December 19, 2013. For additional information regarding Mr. Sanchez refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 6 Column: b

Mr. Egan was elected December 19, 2013. For additional information regarding Mr. Egan refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 7 Column: b

Mr. Cannon was elected December 19, 2013. For additional information regarding Mr. Cannon refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 9 Column: b

Mr. Mughal was elected August 12, 2013. For additional information regarding Mr. Mughal refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 12 Column: b

Mr. Halkyard resigned September 14, 2013. For additional information regarding Mr. Halkyard refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 13 Column: b

Mr. Kaleta resigned December 19, 2013. For additional information regarding Mr. Kaleta refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 14 Column: b

Ms. Samil was named Executive Vice President, Transition December 19, 2013.

Schedule Page: 104 Line No.: 15 Column: b

Mr. Denis resigned December 19, 2013. For additional information regarding Mr. Denis refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 16 Column: b

Mr. Stewart resigned December 19, 2013. For additional information regarding Mr. Stewart refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 104 Line No.: 17 Column: b

Ms. Cobb was named Senior Vice President Human Resources and Information Technology Transition December 19, 2013.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Board of Directors as of December 31, 2013	
2	Paul J. Caudill - President	6226 W. Sahara Ave., Las Vegas, NV 89146
3	E. Kevin Bethel - Sr VP, Chief Financial Officer	6226 W. Sahara Ave., Las Vegas, NV 89146
4	Douglas A. Cannon - Sr VP, General Counsel, Corp. Sec.	6226 W. Sahara Ave., Las Vegas, NV 89146
5	Patrick S. Egan - Sr VP, Customer Operations	6226 W. Sahara Ave., Las Vegas, NV 89146
6	Kevin C. Geraghty	6226 W. Sahara Ave., Las Vegas, NV 89146
7	Francis P. Gonzales	6226 W. Sahara Ave., Las Vegas, NV 89146
8	John C. Owens	6100 Neil Rd, Reno, NV 89511
9	Tony F. Sanchez, III-Sr VP, Government & Community Strategy	6226 W. Sahara Ave., Las Vegas, NV 89146
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11	Other Directors in 2013	
12	Joseph B. Anderson, Jr	3026 Oak Creek Dr., Wixom, MI 48393
13	Glenn C. Christenson	1528 MacDonald Ranch Dr., Henderson, NV 89012
14	Susan F. Clark	302 S. Bronough St., Suite 200, Tallahassee, FL 32301
15	Stephen E. Frank	5865 Strasbourg Ct., Reno, NV 89511
16	Brian J. Kennedy	4790 Caughlin Pkwy., Suite 501, Reno, NV 89519
17	Maureen T. Mullarkey	925 Dartmouth Dr., Reno, NV 89509
18	John F. O'Reilly	325 S. Maryland Pkwy., Las Vegas, NV 89101
19	Phillip G. Satre	457 Court St., Reno, NV 89501
20	Donald D. Snyder	4505 S. Maryland Pkwy., Las Vegas, NV 89154
21	Michael W. Yackira - Chief Executive Officer	6226 W. Sahara Ave., Las Vegas, NV 89146
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Schedule Page: 105 Line No.: 2 Column: a
Mr. Caudill was elected December 19, 2013. For additional information regarding Mr. Caudill refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 3 Column: a
Mr. Bethel was elected December 19, 2013. For additional information regarding Mr. Bethel refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 4 Column: a
Mr. Cannon was elected December 19, 2013. For additional information regarding Mr. Cannon refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 5 Column: a
Mr. Egan was elected December 19, 2013. For additional information regarding Mr. Egan refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 6 Column: a
Mr. Geraghty was elected December 19, 2013. For additional information regarding Mr. Geraghty refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 7 Column: a
Mr. Gonzales was elected December 19, 2013. For additional information regarding Mr. Gonzales refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 8 Column: a
Mr. Owens was elected December 19, 2013. For additional information regarding Mr. Owens refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 9 Column: a
Mr. Sanchez was elected December 19, 2013. For additional information regarding Mr. Sanchez refer to Page 108, *Important Changes During the Year*, Item 13 of this Form No. 1.

Schedule Page: 105 Line No.: 12 Column: a
Mr. Anderson resigned December 19, 2013. For additional information regarding Mr. Anderson refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 13 Column: a
Mr. Christenson resigned December 19, 2013. For additional information regarding Mr. Christenson refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 14 Column: a
Ms. Clark resigned December 19, 2013. For additional information regarding Ms. Clark refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 15 Column: a
Mr. Frank resigned December 19, 2013. For additional information regarding Mr. Frank refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 16 Column: a
Mr. Kennedy resigned December 19, 2013. For additional information regarding Mr. Kennedy refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 17 Column: a
Ms. Mullarkey resigned December 19, 2013. For additional information regarding Ms. Mullarkey refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 18 Column: a
Mr. O'Reilly resigned December 19, 2013. For additional information regarding Mr. O'Reilly refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 19 Column: a
Mr. Satre resigned December 19, 2013. For additional information regarding Mr. Satre refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 20 Column: a
Mr. Snyder resigned December 19, 2013. For additional information regarding Mr. Snyder refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Schedule Page: 105 Line No.: 21 Column: a
Mr. Yackira resigned December 19, 2013. For additional information regarding Mr. Yackira refer to Page 108, *Important Changes During the Year*, Item 13, of this Form 1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

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

Does the respondent have formula rates? ☒ Yes ☐ No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Rate Schedule No. 57	ER10-2107-000 & ER11-1836-000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20130417-8025	04/17/2013	N/A	SPPC Annual FERC Form 1	Electric Rate Schedule No. 57
2					
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INFORMATION ON FORMULA RATES
Formula Rate Variances

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

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

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

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

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

1. None.

2. *MidAmerican Merger*

On December 19, 2013, the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013 ("Merger Agreement"), among MidAmerican Energy Holdings Company (MEHC), Silver Merger Sub, Inc. ("Merger Sub"), MEHC's wholly owned subsidiary, and NV Energy, whereby Merger Sub was merged into NV Energy and NV Energy became an indirect wholly owned subsidiary of MEHC ("MEHC Merger") was completed.

The transaction was approved by the boards of directors of both NV Energy and MEHC and the shareholders of NV Energy. MEHC received unconditional approval of the MEHC Merger from the FERC on December 19, 2013 and the Federal Communications Commission on September 27, 2013. The United States Department of Justice and the Federal Trade Commission granted early termination of the mandatory waiting period under the Hart-Scott-Rodino Antitrust Improvement Act of 1976 on July 22, 2013. On December 17, 2013, the PUCN approved the Joint Application filed by MEHC and NV Energy, subject to certain stipulations. The stipulations included, among others:

- A one-time bill credit to retail customers of Sierra Pacific Power (the Company) of $5 million credited to retail customers over one billing cycle beginning within 30 days of the close of the MEHC Merger.
- MEHC and NV Energy agreed to not seek recovery of the acquisition premium, transaction and transition costs associated with the MEHC Merger from customers.
- The Company will not seek to collect lost revenues as described in section 704.9524 of the Nevada Administrative Code for calendar year 2013 in 2014 rates, and will not seek collection of lost revenues in excess of 50% of what the Company could otherwise request for calendar year 2014 in 2015 rates. NV Energy also agreed to work cooperatively with PUCN staff and the Nevada Bureau of Consumer Protection to develop a legislative or administrative alternative to the current mechanism that would retain the objective of encouraging investment in energy efficiency and that is acceptable to NV Energy, PUCN staff and the Nevada Bureau of Consumer Protection. NV Energy and the Nevada Bureau of Consumer Protection also agree to work in good faith to have a legislative or administrative alternative adopted.
- Normal rate case rules and procedures apply to costs and revenues, and any under or over earnings will accrue to the Company until the next rate case filing after 2014, subject to specified adjustments for intercompany charges from MEHC and its other subsidiaries as described in the PUCN Joint Application. The commitment does not preclude parties from proposing any other adjustments to test year or certification period results.

One Company Merger Between Sierra Pacific Power Company and Nevada Power Company

Sierra Pacific Power Company and Nevada Power Company filed a joint application with the PUCN to merge Sierra Pacific into Nevada Power (“One Company Merger”) and to call the surviving entity NV Energy Operating Company (NVEOC). The One Company Merger was approved by the FERC on November 26, 2013 per FERC Docket. No. EC13-113-00, and is awaiting approval by the PUCN.

3. None.

4. None.

5. On December 31, 2013, the Company, along with Nevada Power Company, completed construction and placed in-service ON Line, a 231 mile, 500-kV transmission line connecting the Company's and Nevada Power's service territories. ON Line will enable the Company and Nevada Power to optimize their generation assets by enhancing their transmission capabilities. ON Line provides the ability to jointly dispatch energy throughout Nevada and provide access to renewable energy resources in parts of northern and eastern Nevada, which will enhance the Company's and Nevada Power's ability to manage and optimize their generating facilities. ON Line provides between 600 and 800 MW of transfer capability between northern and southern Nevada. ON Line was a joint project between the Company, Nevada Power and Great Basin Transmission, LLC. With the completion of ON Line, the parties completed construction of a 500-kV interconnection between the Robinson Summit substation on the Nevada Power system and the Harry Allen substation on the Company's system. The Company and Nevada Power own a 25% interest in ON Line and have entered into a long-term transmission use agreement with Great Basin Transmission, LLC for its 75% interest in ON Line for a term of 41 years. The Company's and Nevada Power's share of their 25% interest in ON Line and the long-term transmission use agreement is split at 5% and 95%, respectively.

6. The consummation of the MEHC Merger triggered mandatory redemption requirements under financing agreements of the Company. As a result, the Company offered to purchase $702 million of debt at 101% of par. The tender offer expired in January 2014 with no amounts tendered.

   In August 2013, the Company issued and sold $250 million of its 3.375% Series T General and Refunding Securities, due 2023. The $248 million in net proceeds was used, together with cash on hand, to pay at maturity the $250 million principal amount of its 5.45% Series Q General and Refunding Securities, which matured in September 2013.

7. None.

8. None.

9. *Newmont Nevada Energy Investment - TS Power Plant*

   Newmont Nevada Energy Investment, LLC ("Newmont") owns a 203 megawatt coal-fired power plant facility located in Eureka County, NV (the "TS Power Plant") that is interconnected to the Company's transmission system. As a result of system modifications required for the ON Line, (a 500-kilovolt transmission line connecting the Company and Nevada Power Company, an electric utility wholly owned by NV Energy), Newmont will need to install certain protection equipment at its TS Power Plant. Newmont brought suit against the Company in the Second Judicial District of Nevada (Washoe County) seeking declaratory relief and to enjoin the operation at full capacity of certain equipment (series capacitors) to be installed by the Company for the ON Line project, until such time as Newmont completes the design, fabrication and installation of protection equipment at its power plant to protect its generator from potential adverse effects caused by the operation of the Company's equipment at full capacity. In addition, Newmont's complaint asserted a claim under the parties' interconnection agreement seeking to recover the cost of making the necessary modifications to the TS Power Plant.

A hearing on Newmont's motion for a preliminary injunction was held during the week of August 12, 2013, after which the trial court concluded that it would enter an order enjoining the Company from operating its equipment (series capacitors) at full capacity from January 1, 2014 until approximately April 8, 2014, and from approximately June 1, 2014 to June 30, 2014 (or the time Newmont has completed the installation of its protection equipment), so as to allow installation and testing of protection equipment at the TS Power Plant. The district court issued the order on December 17, 2013. Newmont posted the required $1 million bond and subsequently filed a complaint with the Federal Energy Regulatory Commission in Docket No. EL14-16-000 to address the issue of who will pay for the protection equipment and the installation at the TS Power Plant. On April 9, 2014, the FERC issued an order directing the Company to pay the costs of studies relating to subsynchronous resonance conducted by Newmont and the installation of the protection equipment at the TS Power Plant, which are estimated to be $1 million and $11 million, respectively.

Caughlin Fire

On November 18, 2011, a fire was reported in the hills near Reno, Nevada (the "Caughlin Fire"). In January 2012, the Reno Fire Department issued a report in which they opined that "this fire was most likely the result of an electrical event in the area," and that "something such as a tree branch hitting the power-line" was a likely cause of the fire. The Company is continuing its investigation in the matter.

To date, six subrogation lawsuits and two individual claimant lawsuits have been filed against the Company in relation to the Caughlin Fire. The subrogation lawsuits have been brought by various insurance companies, and involve similar causes of action (negligence, inverse condemnation, trespass, nuisance, subrogation and strict liability). One of the individual claimant lawsuits identifies six plaintiffs, while the other individual claimant lawsuit purports to be brought on behalf of a class of similarly affected individuals within the fire perimeter who suffered damage or loss of use of their property as a result of the Caughlin Fire and the evacuation order associated with it.

All of the cases have been consolidated before a single judge in Washoe County, Nevada. The court has not yet entered a scheduling order in this case. At this time, management cannot assess or predict what the impact or outcome of this litigation may be, or what, if any, other litigation may be brought on this matter.

10. None.

11. N/A

12. N/A.

13. The following is an overview of the officer and director changes of Sierra Pacific Power Company, for a further discussion of officer and director changes during the year, refer to page 104, *Officers* and page 105, *Directors* of this Form No. 1.

On August 12, 2013, Mohammed N. Mughal, was elected Treasurer and Executive, Financial Strategies.

On August 30, 2013, Jonathan K. Halkyard resigned as Executive Vice President and Chief Financial Officer, effective September 13, 2013.

On August 31, 2013, E. Kevin Bethel was appointed Vice President and Chief Financial Officer, effective September 16, 2013. On December 19, 2013, Mr. Bethel was appointed Senior Vice President and Chief Financial Officer. Mr. Bethel previously held the position of Vice President, Chief Accounting Officer and Controller.

On December 19, 2013, Michael W. Yackira, Chief Executive Officer and Director, announced his intent to retire in June of 2014.

On December 19, 2013, Paul J. Kaleta resigned as Senior Vice President, General Counsel.

On December 19, 2013, Roberto R. Denis resigned as Senior Vice President, Energy Delivery.

On December 19, 2013, Robert E. Stewart resigned as Senior Vice President, Customer Relationship.

On December 19, 2013, Dilek L. Samil, was named Executive Vice President, assisting in the transition.

On December 19, 2013, Alice A. Cobb was named Senior Vice President, Human Resources and Information Technology, assisting in the transition.

On December 19, 2013, the Board of Directors elected the following new officers:

- Paul J. Caudill, President
- Douglas A. Cannon, Senior Vice President, General Counsel and Corporation Secretary, Chief Compliance Officer
- Patrick S. Egan, Senior Vice President, Customer Satisfaction

On December 19, 2013, the following directors resigned, effective upon the closing of MidAmerican's acquisition of Sierra Pacific Power Company:

- Michael W. Yackira
- Joseph B. Anderson, Jr.
- Glenn C. Christenson
- Susan F. Clark
- Stephen E. Frank
- Brian J. Kennedy
- Maureen T. Mullarkey
- John F. O'Reilly
- Phillip G. Satre
- Donald D. Snyder

On December 19, 2013, the Board of Directors elected the following individuals as new directors, effective upon the closing of MidAmerican's acquisition of Sierra Pacific:

- Paul J. Caudill, President
- E. Kevin Bethel, Senior Vice President and Chief Financial Officer
- Douglas A. Cannon, Senior Vice President, General Counsel and Corporate Secretary, Chief Compliance Officer
- Patrick S. Egan, Senior Vice President, Customer Operations
- Kevin C. Geraghty, Vice President, Generation
- Francis P. Gonzales, Vice President, Electric Delivery
- John C. Owens, Vice President, Gas Delivery
- Tony F. Sanchez, Senior Vice President, Government & Community Strategy

14. N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	3,764,444,743	3,667,487,193
3	Construction Work in Progress (107)	200-201	88,869,338	140,167,950
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,853,314,081	3,807,655,143
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,519,672,250	1,482,292,196
6	Net Utility Plant (Enter Total of line 4 less 5)		2,333,641,831	2,325,362,947
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,333,641,831	2,325,362,947
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,215,655	2,215,655
19	(Less) Accum. Prov. for Depr. and Amort. (122)		1,884,063	1,852,645
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		7,148,280	6,136,456
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		17,966,929	0
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		95,094	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		25,541,895	6,499,466
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,758,890	4,225,322
36	Special Deposits (132-134)		1,000	459,000
37	Working Fund (135)		850	5,850
38	Temporary Cash Investments (136)		64,635,127	56,364,804
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		49,512,788	45,160,562
41	Other Accounts Receivable (143)		38,168,663	25,359,327
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,143,707	1,125,348
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		10,350,547	10,350,547
45	Fuel Stock (151)	227	11,638,247	29,337,730
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	29,722,069	29,463,563
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	76,317	522,609
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		1,233,837	1,337,609
57	Prepayments (165)		13,706,534	11,203,891
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		69,197,932	53,424,120
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		95,094	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		95,094	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		289,859,094	266,089,586
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		10,784,737	10,153,307
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	307,770,251	290,411,518
73	Prelim. Survey and Investigation Charges (Electric) (183)		44,005	568,953
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		2,867	-11,124
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	103,750,419	160,834,845
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		26,611,618	29,089,824
82	Accumulated Deferred Income Taxes (190)	234	131,561,334	124,727,134
83	Unrecovered Purchased Gas Costs (191)		4,756,373	-18,070,320
84	Total Deferred Debits (lines 69 through 83)		585,281,604	597,704,137
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,234,324,424	3,195,656,136

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	end of 2013/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	3,750	3,750
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		190,491,023	190,491,023
7	Other Paid-In Capital (208-211)	253	920,771,103	920,775,310
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	-92,643,700	-70,985,592
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-1,666,112	-1,548,186
16	Total Proprietary Capital (lines 2 through 15)		1,016,956,064	1,038,736,305
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	348,250,000	348,250,000
19	(Less) Reaquired Bonds (222)	256-257	133,575,000	133,575,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	951,742,000	951,742,000
22	Unamortized Premium on Long-Term Debt (225)		10,103,097	11,766,202
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		655,858	307,211
24	Total Long-Term Debt (lines 18 through 23)		1,175,864,239	1,177,875,991
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		23,215,554	1,114,395
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,636,716	1,347,841
29	Accumulated Provision for Pensions and Benefits (228.3)		51,106,605	103,716,789
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		110,616	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		16,648,089	14,721,633
35	Total Other Noncurrent Liabilities (lines 26 through 34)		92,717,580	120,900,658
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		115,481,982	94,653,463
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		33,771,321	21,534,109
41	Customer Deposits (235)		14,317,830	13,387,028
42	Taxes Accrued (236)	262-263	3,131,734	2,326,748
43	Interest Accrued (237)		15,120,221	16,464,398
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	end of 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		14,149,012	12,727,649
48	Miscellaneous Current and Accrued Liabilities (242)		3,562,229	11,609,884
49	Obligations Under Capital Leases-Current (243)		601,622	235,301
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		200,135,951	172,938,580
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		17,746,910	17,825,966
57	Accumulated Deferred Investment Tax Credits (255)	266-267	7,502,496	8,850,489
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	52,309,328	31,855,866
60	Other Regulatory Liabilities (254)	278	61,543,096	56,130,735
61	Unamortized Gain on Reaquired Debt (257)		177,724	186,318
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		499,228,449	463,813,037
64	Accum. Deferred Income Taxes-Other (283)		110,142,587	106,542,191
65	Total Deferred Credits (lines 56 through 64)		748,650,590	685,204,602
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,234,324,424	3,195,656,136

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	924,275,282	877,992,692		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	571,056,841	523,173,854		
5	Maintenance Expenses (402)	320-323	30,145,256	35,360,805		
6	Depreciation Expense (403)	336-337	90,759,778	89,497,558		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	12,956,968	11,308,219		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337		145,673		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		19,331,285	7,464,544		
13	(Less) Regulatory Credits (407.4)		496,839	496,839		
14	Taxes Other Than Income Taxes (408.1)	262-263	24,851,720	23,387,974		
15	Income Taxes - Federal (409.1)	262-263	-2,211,315	-8,692,691		
16	- Other (409.1)	262-263	-111,418	-393,108		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	349,860,300	49,102,777		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	312,970,649			
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,347,993	-1,137,008		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		31	76		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		781,823,903	728,721,682		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		142,451,379	149,271,010		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
802,886,667	769,946,801	121,388,615	108,045,891			2
						3
479,962,196	441,419,849	91,094,645	81,754,005			4
28,220,395	33,376,089	1,924,861	1,984,716			5
78,919,023	78,791,656	11,840,755	10,705,902			6
						7
10,457,310	9,421,799	2,499,658	1,886,420			8
	145,673					9
						10
						11
16,650,422	7,310,770	2,680,863	153,774			12
407,662	407,662	89,177	89,177			13
22,132,467	20,748,282	2,719,253	2,639,692			14
9,510,818	4,905,244	-11,722,133	-13,597,935			15
-111,418	-393,108					16
330,190,915	35,072,514	19,669,385	14,030,263			17
306,018,589		6,952,060				18
-1,286,566	-1,083,814	-61,427	-53,194			19
						20
						21
31	76					22
						23
						24
668,219,280	629,307,216	113,604,623	99,414,466			25
134,667,387	140,639,585	7,783,992	8,631,425			26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		142,451,379	149,271,010		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		7,810	132,686		
34	(Less) Expenses of Nonutility Operations (417.1)		31,419	31,419		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		3,052,435	4,433,021		
38	Allowance for Other Funds Used During Construction (419.1)		2,451,632	2,623,564		
39	Miscellaneous Nonoperating Income (421)		1,821,741	1,871,665		
40	Gain on Disposition of Property (421.1)		2,267,089	2,224,653		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		9,569,288	11,254,170		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-87,266	87,266		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		127,753	1,215,236		
46	Life Insurance (426.2)					
47	Penalties (426.3)		30,549	30,640		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		887,554	989,669		
49	Other Deductions (426.5)		34,077,338	5,131,580		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		35,035,928	7,454,391		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	125,433	83,888		
53	Income Taxes-Federal (409.2)	262-263	-288,191	1,395,589		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277				
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)			-54,246		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-162,758	1,425,231		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-25,303,882	2,374,548		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		57,910,989	59,585,992		
63	Amort. of Debt Disc. and Expense (428)		2,198,746	2,308,874		
64	Amortization of Loss on Reaquired Debt (428.1)		2,670,831	4,437,795		
65	(Less) Amort. of Premium on Debt-Credit (429)		1,663,105	1,663,105		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		994	6,461		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		2,260,994	4,684,251		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,571,856	2,056,311		
70	Net Interest Charges (Total of lines 62 thru 69)		61,805,605	67,291,035		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		55,341,892	84,354,523		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		55,341,892	84,354,523		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		-77,927,592	(142,282,115)
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		55,341,892	84,354,523
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividend		-77,000,000	(20,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-77,000,000	(20,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		-99,585,700	(77,927,592)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Change in Accounting Method for Unbilled Revenue		6,942,000	6,942,000
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		6,942,000	6,942,000
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		6,942,000	6,942,000
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		-92,643,700	(70,985,592)
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

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Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	55,341,892	84,354,523
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	103,716,746	100,951,450
5	Unamortized Loss on Reacquired Debt	2,670,831	3,360,653
6	Regulatory Disallowance	5,469,285	
7	Deferred Energy Costs	-67,442,069	-34,601,517
8	Deferred Income Taxes (Net)	32,181,608	39,183,651
9	Investment Tax Credit Adjustment (Net)	-1,347,993	-1,191,254
10	Net (Increase) Decrease in Receivables	-5,613,684	-6,103,925
11	Net (Increase) Decrease in Inventory	17,466,041	-3,511,408
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	19,693,351	2,182,305
14	Net (Increase) Decrease in Other Regulatory Assets	71,582,330	43,751,219
15	Net Increase (Decrease) in Other Regulatory Liabilities	757,285	-4,213,470
16	(Less) Allowance for Other Funds Used During Construction	2,451,632	2,623,564
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Net Increase (Decrease) in Accrued Taxes & Interest	-1,087,259	-807,309
19	Net (Increase) Decrease in Prepayments	-2,502,643	-4,244,789
20	Risk Management Assets & Liabilities	95,094	
21	Other, net	-2,405,941	-12,234,237
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	226,123,242	204,252,328
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-159,523,493	-223,610,316
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	31,418	31,419
30	(Less) Allowance for Other Funds Used During Construction	-2,451,632	-2,623,564
31	Other (provide details in footnote):		
32	Customer Advances for Construction	-79,056	-2,564,278
33	Contributions in Aid of Construction	18,489,369	44,803,171
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-138,630,130	-178,716,440
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-138,630,130	-178,716,440
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	247,632,280	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	247,632,280	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-251,784,501	-100,028
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-77,000,000	-20,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-81,152,221	-20,100,028
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	6,340,891	5,435,860
87			
88	Cash and Cash Equivalents at Beginning of Period	61,054,976	55,619,116
89			
90	Cash and Cash Equivalents at End of period	67,395,867	61,054,976

Schedule Page: 120 Line No.: 21 Column: b

SPPCO SCF Footnotes
Annual FERC Form 1 - December 31, 2013

Other Assets	$ 8,375,289
Regulatory Asset for Pension Plan	51,135,283
Other Liabilities	8,779,427
Pension and Benefit Liability	(70,578,015)
Accumulated Other Comprehensive Income	(117,925)
Total: Other Net	**$ (2,405,941)**

Schedule Page: 120 Line No.: 21 Column: c

SPPCO SCF Footnotes
Annual FERC Form 1 - December 31, 2012

Other Assets	$ (226,671)
Regulatory Asset for Pension Plan	(36,109,796)
Other Liabilities	2,594,781
Pension and Benefit Liability	21,671,486
Accumulated Other Comprehensive Income	(164,037)
Total: Other Net	**$ (12,234,237)**

NOTES TO FINANCIAL STATEMENTS

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

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

SIERRA PACIFIC POWER COMPANY
NOTES TO FINANCIAL STATEMENTS

The notes below have been excerpted from Sierra Pacific Power Company's (SPPC) Annual Report on Form 10-K for the year ended December 31, 2013 and are prepared in conformity with generally accepted accounting principles. Accordingly, certain footnotes are not reflective of SPPC'S Financial Statements contained herein.

(1) Organization and Operations

Sierra Pacific Power Company ("Sierra Pacific"), together with its subsidiaries (collectively, the "Company"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Nevada Power Company ("Nevada Power") and certain other subsidiaries. The Company is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers primarily in northern Nevada and regulated retail natural gas customers in Nevada. NV Energy is an indirect wholly owned subsidiary of MidAmerican Energy Holdings Company ("MEHC"). MEHC is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

On December 19, 2013, the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013, among MEHC, Silver Merger Sub, Inc. ("Merger Sub"), MEHC's wholly owned subsidiary, and NV Energy, whereby Merger Sub was merged into NV Energy and NV Energy became an indirect wholly owned subsidiary of MEHC ("MEHC Merger")was completed.

The transaction was approved by the boards of directors of both NV Energy and MEHC and the shareholders of NV Energy. MEHC received unconditional approval of the MEHC Merger from the Federal Energy Regulatory Commission ("FERC") on December 19, 2013 and the Federal Communications Commission on September 27, 2013. The United States Department of Justice and the Federal Trade Commission granted early termination of the mandatory waiting period under the Hart-Scott-Rodino Antitrust Improvement Act of 1976 on July 22, 2013. On December 17, 2013, the Public Utilities Commission of Nevada ("PUCN") approved the Joint Application filed by MEHC and NV Energy, subject to certain stipulations. The stipulations included, among others:

- A one-time bill credit to retail customers of the Company of $5 million credited to retail customers over one billing cycle beginning within 30 days of the close of the MEHC Merger.
- MEHC and NV Energy agreed to not seek recovery of the acquisition premium, transaction and transition costs associated with the MEHC Merger from customers.
- The Company will not seek to collect lost revenues as described in section 704.9524 of the Nevada Administrative Code for calendar year 2013 in 2014 rates, and will not seek collection of lost revenues in excess of 50% of what the Company could otherwise request for calendar year 2014 in 2015 rates. NV Energy also agreed to work cooperatively with PUCN staff and the Nevada Bureau of Consumer Protection ("BCP") to develop a legislative or administrative alternative to the current mechanism that would retain the objective of encouraging investment in energy efficiency and that is acceptable to NV Energy, PUCN staff and the BCP. NV Energy and the BCP also agree to work in good faith to have a legislative or administrative alternative adopted.
- Normal rate case rules and procedures apply to costs and revenues, and any under or over earnings will accrue to the Company until the next rate case filing after 2014, subject to specified adjustments for intercompany charges from MEHC and its other subsidiaries as described in the PUCN Joint Application. The commitment does not preclude parties from proposing any other adjustments to test year or certification period results.

(2) Summary of Significant Accounting Policies

Basis of Presentation

The impacts of acquisition accounting from the MEHC Merger were not reflected on the Financial Statements of the Company.

As a result of the MEHC Merger, the Company has elected to present its Financial Statements and Notes to Financial Statements for the current year and prior years similar to MEHC. Certain amounts from prior years have been reclassed to conform to the current period presentation. The change in format did not have an effect on net income, total assets, total shareholder's equity or cash flows from operations.

The Company's accounts for electric and gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences of this basis of accounting from GAAP include, but not necessarily limited to, the accounting for and classification of:

- The requirement to report deferred tax assets and liabilities separately rather than a single amount.
- The classification of cost of removal as accumulated depreciation rather than regulatory liabilities.
- The removal of certain tax liabilities related to the accounting for uncertain tax positions as deferred income taxes and deferred credits.
- The classification of certain assets and liabilities as noncurrent instead of current.
- The classification of certain items as revenue rather than purchased power expense.
- The classification of income taxes as operating expense rather than income tax expense.
- The classification of certain regulatory liabilities as regulatory assets.
- The classification of merger related costs as non-operating rather than operating.
- The classification of the ON Line transmission line as a capital lease asset and obligation rather than plant and long-term debt.

Use of Estimates in Preparation of Financial Statements

The preparation of the Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") 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 revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Financial Statements.

Accounting for the Effects of Certain Types of Regulation

The Company prepares its Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Company defers the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated rates. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which will be recognized in earnings in the periods the corresponding changes in regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated rates by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition that could limit the Company's ability to recover its costs. The Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other current assets on the Balance Sheets.

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on the Company's assessment of the collectability of amounts owed to the Company by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. The Company also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. As of December 31, 2013 and 2012, the allowance for doubtful accounts totaled $1 million and is included in accounts receivable, net on the Balance Sheets.

Derivatives

The Company employs a number of different derivative contracts, including forwards, futures, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities; and interest rate risk. Derivative contracts are recorded on the Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP.

Commodity derivatives used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as cost of fuel, energy and capacity or natural gas purchased for resale on the Statements of Income.

For the Company's 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 and liabilities.

For the Company's derivatives designated as hedging contracts, the Company formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The Company formally documents hedging activity by transaction type and risk management strategy.

Inventories

Inventories consist mainly of materials and supplies totaling $30 million and $29 million as of December 31, 2013 and 2012, respectively, and fuel, which includes coal stocks, stored gas and fuel oil totaling $13 million and $31 million as of December 31, 2013 and 2012, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the PUCN.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by the Company's various regulatory authorities. Depreciation studies are completed by the Company to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when the Company retires or sells a component of regulated property, plant and equipment, it charges the original cost, net of any proceeds from the disposition, to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

Debt and equity AFUDC, which represents the estimated costs of debt and equity funds necessary to finance the construction of regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Statements of Income. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, the Company is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets. The Company's AFUDC rate used during both 2013 and 2012 was 7.86% for electric, 5.15% for natural gas and 7.59% for common facilities. As specified by the PUCN, certain projects may be assigned a lower or higher AFUDC rate due to specific interest-rate financings directly associated with those projects.

Asset Retirement Obligations

The Company recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Company's AROs are primarily associated with its generating facilities. The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO liability is adjusted for any revisions to the original estimate of undiscounted cash flows (with corresponding adjustments to property, plant and equipment) and for accretion of the ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability on the Balance Sheets.

Management's methodology to assess its legal obligation includes an inventory of assets by the Company's system and components and a review of rights of way and easements, regulatory orders, leases and federal, state and local environmental laws. Additionally, management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Poly Chlorinated Biphenyl have met the requirements for an ARO.

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value. The impacts of regulation are considered when evaluating the carrying value of regulated assets. For all other assets, any resulting impairment loss is reflected on the Statements of Income.

Income Taxes

Berkshire Hathaway commenced including the Company in its United States federal income tax return on December 20, 2013 in connection with the MEHC Merger. Prior to December 20, 2013, the Company filed a consolidated United States federal income tax return with NV Energy. Consistent with established regulatory practice, the Company's provision for income taxes has been computed on a separate return basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of other comprehensive income ("OCI") are charged or credited directly to OCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits and expense for certain property-related basis differences and other various differences that the Company is required to pass on to its customers in Nevada are charged or credited directly to a regulatory asset or liability. As of December 31, 2013 and 2012, these amounts were recognized as regulatory assets of $96 million and $100 million, respectively, and regulatory liabilities of $9 million and $10 million, respectively, and will be included in regulated rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more-likely-than-not to be realized. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties.

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. The Company's income tax returns are subject to continuous examinations by federal and local income tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The Company recognizes the tax benefit from an uncertain tax position only if it is more-likely-than-not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Financial Statements from such a position are measured based on the largest benefit that is more-likely-than-not of being realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state, local and foreign income tax examinations is uncertain, the Company believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income tax liabilities that may result from these examinations, if any, is not expected to have a material impact on the Company's financial results. The Company's unrecognized tax benefits are primarily included in accrued property, income and other taxes and other long-term liabilities on the Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Statements of Income.

Revenue Recognition

Revenue is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2013 and 2012, unbilled revenue was $65 million and $50 million, respectively, and is included in accounts receivable, net on the Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. The Company records sales, franchise and excise taxes collected directly from customers and remitted directly to the taxing authorities on a net basis on the Statements of Income.

The Company primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, the Company may not take physical delivery of the energy or natural gas. The Company may sell the excess energy or natural gas to the wholesale market. In such instances, it is the Company's policy to record such sales net in cost of fuel, energy and capacity.

Unamortized Debt Premiums, Discounts and Financing Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2013-04, which amends FASB Accounting Standards Codification ("ASC") Topic 405, "Liabilities." The amendments in this guidance require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the amount the reporting entity agreed to pay plus any additional amounts the reporting entity expects to pay on behalf of its co-obligor. Additionally, the guidance requires the entity to disclose the nature and amount of the obligation, as well as other information about those obligations. This guidance is effective for interim and annual reporting periods beginning after December 15, 2013. The Company adopted this guidance on January 1, 2014. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Financial Statements.

In February 2013, the FASB issued ASU No. 2013-02, which amends FASB ASC Topic 220, "Comprehensive Income." The amendments in this guidance require an entity to provide information about the amounts reclassified out of AOCI by component. In addition, an entity is required to present, either on the face of the financial statements or in the notes, significant amounts reclassified out of AOCI by the respective line items of net income if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required by GAAP that provide additional detail about those amounts. The Company adopted this guidance on January 1, 2013. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Financial Statements.

In December 2011, the FASB issued ASU No. 2011-11, which amends FASB ASC Topic 210, "Balance Sheet." The amendments in this guidance require an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. In January 2013, the FASB issued ASU No. 2013-01, which also amends FASB ASC Topic 210 to clarify that the scope of ASU No. 2011-11 only applies to derivative instruments, repurchase agreements, reverse purchase agreements and securities borrowing and securities lending transactions that are either being offset or are subject to an enforceable master netting arrangement or similar agreement. The Company adopted the guidance on January 1, 2013. The adoption of the guidance did not have a material impact on the Company's disclosures included within Notes to Financial Statements.

(3) Merger-Related Activities

On December 17, 2013, the PUCN approved the Joint Application related to the MEHC Merger filed by MEHC and NV Energy, subject to certain stipulations. The stipulations included, among others, a one-time bill credit to retail customers of the Company of $5 million credited to retail customers over one billing cycle beginning within 30 days of the close of the MEHC Merger. The bill credit was included as a reduction to operating revenue on the Statements of Income for the year ended December 31, 2013.

The Company incurred costs totaling $20 million related to the MEHC Merger, consisting of: (i) $6 million for amounts payable under NV Energy's change in control policy; (ii) $7 million for accelerated vesting and stock compensation under NV Energy's long-term incentive plan; (iii) $6 million for investment banker fees paid by NV Energy and (iv) $1 million for legal and other expenses. The costs were included in merger-related expenses on the Statements of Income for the year ended December 31, 2013.

(4) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	2013	2012
Utility plant in-service:		
Electric generation	$ 1,070	$ 1,060
Electric distribution	1,289	1,256
Electric transmission	685	678
Electric intangible plant	138	102
Natural gas distribution	357	341
Natural gas intangible plant	13	13
Common general	212	218
Utility plant in-service	3,764	3,668
Accumulated depreciation and amortization	(1,301)	(1,278)
Utility plant in-service, net	2,463	2,390
Construction work-in-progress	89	140
Property, plant and equipment, net	$ 2,552	$ 2,530

All of the Company's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. The Company's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the average depreciable property balances was 3.02% and 2.94% during 2013 and 2012, respectively. The Company is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

Impairment of Regulated Assets Not In Rates

The Company recorded an impairment charge of $4 million in operating and maintenance expense on the Statements of Income for the year ended December 31, 2013 related to the recovery of certain assets not currently in rates.

(5) Regulatory Matters

Regulatory assets represent costs that are expected to be recovered in future rates. The Company's regulatory assets reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2013	2012
Deferred income taxes[1]	29 years	$ 96	$ 100
Employee benefit plans[2]	13 years	90	140
Merger costs from 1999 merger	32 years	90	95
Abandoned projects	10 years	59	42
Legacy meters	6 years	24	3
Deferred excess energy costs	1 year	17	—
Unrealized loss on regulated derivative contracts	14 years	13	—
Asset retirement obligations	11 years	10	9
Other	Various	43	80
Total regulatory assets		$ 442	$ 469
Reflected as:			
Current assets		$ 15	$ —
Noncurrent assets		427	469
Total regulatory assets		$ 442	$ 469

(1) Amounts primarily represent income tax benefits related to accelerated tax depreciation and certain property-related basis differences that were previously flowed through to customers and will be included in regulated rates when the temporary differences reverse.

(2) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in regulated rates when recognized.

The Company had regulatory assets not earning a return on investment of $232 million and $203 million as of December 31, 2013 and 2012, respectively, that primarily related to deferred income taxes, 1999 merger costs, a portion of deferred excess energy costs and unrealized loss on regulated derivative contracts.

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. The Company's regulatory liabilities reflected on the Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2013	2012
Cost of removal[1]	42 years	$ 219	$ 203
Renewable energy program	1 year	24	—
Energy efficiency program	1 year	12	5
Deferred income taxes	18 years	9	10
Deferred energy over collected	—	—	51
Other	Various	16	8
Total regulatory liabilities		$ 280	$ 277
Reflected as:			
Current liabilities		$ 37	$ 51
Noncurrent liabilities		243	226
Total regulatory liabilities		$ 280	$ 277

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing regulated property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Statements of Income but rather is deferred and recorded as a regulatory asset on the Balance Sheets and is included in the table above as deferred excess energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy over collected. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Energy Efficiency Implementation Rates and Energy Efficiency Program Rates

In July 2010, regulations were adopted by the PUCN that authorizes an electric utility to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN through energy efficiency implementation rates ("EEIR"). As a result, the Company files annually in March to adjust energy efficiency program rates and EEIR for over- or under-collected balances, which are effective in October of the same year.

In March 2013, the Company filed applications with the PUCN for the twelve-month period ended December 31, 2012 to reset EEIR elements. In September 2013, the PUCN issued an order indicating that EEIR revenue should not contribute to the Company earning more than its authorized rate of return. As the Company earned in excess of its authorized rate of return in 2012, the PUCN disallowed approximately $5 million in EEIR revenue (including carrying charges) and the Company recorded a charge to operating and maintenance expense on the Statements of Income for the year ended December 31, 2013.

The PUCN's final order approving the MEHC Merger stipulated that the Company, will not seek recovery of any lost revenue for calendar year 2013 and, for calendar year 2014, in an amount that exceeds 50% of the lost revenue that the Company could otherwise request. As a result, for the year ended December 31, 2013, the Company has not recorded revenue for EEIR and has recorded a regulatory liability of $5 million, which is included in current regulatory liabilities on the Balance Sheets. On February 28, 2014, the Company filed an application with the PUCN to reset EEIR and energy efficiency program rates. Pursuant to the stipulation, the Company established credits to return EEIR revenue collected in the 2013 calendar year. To effect the merger stipulation, the Company proposed to suspend collection of the EEIR on October 1, 2014, and defer implementation of a new EEIR until January 1, 2015.

FERC Matters

2012 FERC Transmission Rate Case

In October 2012, the Company filed an application with the FERC to revise transmission and ancillary service rates that were last set in 2007 and 2003, respectively. In December 2012, the FERC issued an order which suspended the proposed rate increases until June 1, 2013. Furthermore, as requested in the filing, the FERC accepted two proposed rate decreases effective January 1, 2013. On June 17, 2013, the Company filed an unopposed settlement agreement resolving all issues with the FERC, for approval of rates effective June 1, 2013. The FERC approved the settlement on August 29, 2013. The rate changes under the terms of the settlement agreement result in an overall annual revenue increase of $2 million.

2013 FERC Transmission Rate Case

In May 2013, the Company, along with Nevada Power, filed an application with the FERC to establish single system transmission and ancillary service rates. The combined filing requested incremental rate relief of $17 million annually to be effective January 1, 2014. On August 5, 2013, the FERC granted the companies' request for a rate effective date of January 1, 2014 subject to refund, and set the case for hearing or settlement discussions. On January 1, 2014, the Company implemented the filed rates in this case subject to refund as set forth in FERC's order. At this time management is unable to determine the final revenue impact of the case.

(6) Credit Facility

The Company's $250 million revolving credit facility expires in 2017, is for general corporate purposes and provides for the issuances of letters of credits. As of December 31, 2013 and 2012, the Company had no drawings outstanding and $6 million in letters of credit issued on its revolving credit facility. Amounts due under the Company's credit facility are collateralized by the Company's general and refunding mortgage bonds. The rate for outstanding loans under the Company's credit facility will be at either an applicable base rate (defined as the highest of the Prime Rate, the Federal Funds Rate plus 0.5% and the London Interbank Offered Rate ("LIBOR") Base Rate plus 1.0%) plus a margin, or a LIBOR rate plus a margin. The margin varies based upon the Company's credit rating by Standard & Poor's and Moody's Investors Services. As of December 31, 2013, the Company's applicable base rate margin is 0.125% and the LIBOR rate margin is 1.125%. The rate for outstanding letters of credit will be at the LIBOR rate margin plus a fee for the issuing bank.

(7) Long-Term Debt

The Company's long-term debt consists of the following, including unamortized premiums and discounts, as of December 31 (dollars in millions):

	Par Value	2013	2012
General and Refunding Mortgage Securities:			
5.45% Series Q, due 2013	$ —	$ —	$ 250
6.000% Series M, due 2016	450	453	455
3.375% Series T, due 2023	250	250	—
6.750% Series P, due 2037	252	259	259
Variable-rate series (2013-0.459% to 0.463%, 2012-0.572 to 0.579%):			
Pollution Control Revenue Bonds Series 2006A, due 2031	58	58	58
Pollution Control Revenue Bonds Series 2006B, due 2036	75	75	75
Pollution Control Revenue Bonds Series 2006C, due 2036	81	81	81
Capital and financial lease obligations - 3.01% to 8.52%, due through 2054	24	24	1
Total long-term debt	$ 1,190	$ 1,200	$ 1,179
Reflected as:			
Current liabilities		$ 1	$ 250
Noncurrent liabilities		1,199	929
Total long-term debt		$ 1,200	$ 1,179

The consummation of the MEHC Merger also triggered mandatory redemption requirements under financing agreements of the Company. As a result, the Company offered to purchase $702 million of debt at 101% of par. The tender offer expired in January 2014 with no amounts tendered.

In August 2013, the Company issued and sold $250 million of its 3.375% Series T General and Refunding Securities, due 2023. The $248 million in net proceeds was used, together with cash on hand, to pay at maturity the $250 million principal amount of its 5.45% Series Q General and Refunding Securities, which matured in September 2013.

Annual Payment on Long-Term Debt

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2014 and thereafter, excluding unamortized premiums and discounts, are as follows (in millions):

2014	$ 1
2015	1
2016	451
2017	1
2018	1
2019 and thereafter	735
Total	$ 1,190

Utility plant of $1.5 billion is subject to the liens of the Company's indentures under which its respective General and Refunding Mortgage Securities are issued.

Capital and Financial Lease Commitments

- The Company has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement.
- The ON Line transmission line was placed in-service on December 31, 2013. The Company and Nevada Power have entered into a transmission use agreement with Great Basin Transmission South, LLC's 75% interest in ON Line. The Company and Nevada Power own the remaining 25% interest. Refer to Note 5 for additional information. The Company's and Nevada Power's share of the long-term transmission use agreement and ownership interest is split at 5% and 95%, respectively. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. An asset of $22 million was recorded as a capital lease asset as of December 31, 2013.

Future cash payments for capital and financial leases as of December 31, 2013, were as follows (in millions):

2014	$	3
2015		2
2016		3
2017		2
2018		3
2019 and thereafter		46
Total minimum lease payments		59
Less amounts representing interest		(35)
Present value of net minimum lease payments	$	24

(8) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, investments held in Rabbi trusts, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities, principally related to derivative contracts, that are measured at fair value on the Balance Sheets 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 Company 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 Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The Company's long-term debt is carried at cost on the Balance Sheets. The fair value of the Company's long-term debt is a Level 2 fair value measurement and has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt as of December 31 (in millions):

	2013		2012	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,176	$ 1,270	$ 1,178	$ 1,302

(9) Other, Net

Other, net as shown on the Statements of Income for the years ended December 31 consists of the following (in millions):

	2013	2012
Interest and dividend income	$ 1	$ 1
Donations	—	(1)
Interest expense on regulatory items	(1)	(1)
Other	6	(3)
Total other, net	$ 6	$ (4)

(10) Income Taxes

Income tax expense (benefit) consists of the following for the years ended December 31 (in millions):

	2013	2012
Current – Federal	$ (2)	$ (7)
Deferred:		
Federal	38	48
State	(2)	—
Total deferred	36	48
Investment tax credits	(1)	(1)
Total income tax expense	$ 33	$ 40

A reconciliation of the federal statutory income rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

	2013	2012
Federal statutory income tax rate	35%	35%
Effects of ratemaking	1	(1)
Non-deductible MEHC Merger related expenses	1	—
Other	—	(2)
Effective income tax rate	37%	32%

The net deferred income tax liability consists of the following as of December 31 (in millions):

	2013	2012
Deferred income tax assets:		
Federal net operating loss and credit carryforwards	$ 61	$ 61
Employee benefits	12	39
Regulatory liabilities	9	27
Capital and financial leases	8	1
Other	40	20
Total deferred income tax assets	130	148
Deferred income tax liabilities:		
Property-related items	(441)	(416)
Regulatory assets	(148)	(155)
Capital and financial leases	(8)	(1)
Other	(10)	(20)
Total deferred income tax liabilities	$ (607)	$ (592)

The following table provides the Company's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2013 (in millions):

Net operating loss carryforwards	$ 161
Deferred income taxes on federal net operating loss carryforwards	$ 56
Expiration dates	2029-2033
Other tax credits	$ 5
Expiration dates	2014-2033

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

A reconciliation of the beginning and ending balances of the Company's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2013	2012
Beginning balance	$ 3	$ 10
Additions for tax positions of prior years	—	2
Reductions for tax positions of prior years	—	(9)
Ending balance	$ 3	$ 3

The unrecognized tax benefits relate to tax positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect the Company's effective income tax rate.

(11) Related Party Transactions

The Company provided electricity and other services to PacifiCorp, an indirect subsidiary of MEHC, of $- million and $3 million for the years ended December 31, 2013 and 2012, respectively.

The Company provided electricity to Nevada Power of $1 million and $1 million for the years ended December 31, 2013 and 2012, respectively. The Company purchased electricity from Nevada Power of $36 million and $20 million for the years ended December 31, 2013 and 2012, respectively. The Company provided intercompany administrative services to Nevada Power of $22 million and $22 million for the years ended December 31, 2013 and 2012, respectively. Nevada Power provided intercompany administrative services to the Company of $24 million and $20 million for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, the Company's Balance Sheets included net amounts due to Nevada Power of $9 million and $1 million, respectively.

The Company has been provided intercompany administrative and shared facility costs from NV Energy of $19 million and $12 million for the years ended December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, the Company's Balance Sheets included amounts due to NV Energy of $28 million and $24 million as of December 31, 2013 and 2012, respectively.

(12) Retirement Plan and Postretirement Benefits

The Company is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provide certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of the Company. The Company contributed $20 million and $15 million to the Qualified Pension Plan and $5 million and $7 million to the Other Postretirement Plans for the years ended December 31, 2013 and 2012, respectively. The Company did not make any contributions to the Non-Qualified Pension Plans for the years ended December 31, 2013 and 2012. Amounts attributable to the Company were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in AOCI.

Amounts receivable from (payable to) NV Energy are included on the Balance Sheets and consist of the following as of December 31(in millions):

	2013	2012
Qualified Pension Plan:		
Other assets	$ 18	$ —
Other long-term liabilities	—	(37)
Non-Qualified Pension Plans:		
Customer deposits and other	(1)	—
Other long-term liabilities	(11)	(12)
Other Postretirement Plans -		
Other long-term liabilities	(38)	(49)

(13) Asset Retirement Obligations

The Company estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

The Company does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $219 million and $203 million as of December 31, 2013 and 2012, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2013	2012
Evaporative ponds and dry ash landfills	$ 7	$ 7
Asbestos	6	5
Other	3	3
Total asset retirement obligations	$ 16	$ 15

The following table reconciles the beginning and ending balances of the Company's ARO liabilities for the years ended December 31, (in millions):

	2013	2012
Beginning balance	$ 15	$ 10
Accretion	1	1
Change in estimated costs	—	4
Ending balance	$ 16	$ 15

Certain of the Company's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, the Company is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Balance Sheets.

(14) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2013 are as follows (in millions):

	2014	2015	2016	2017	2018	2019 and Thereafter	Total
Purchased power	$ 94	$ 96	$ 98	$ 100	$ 77	$ 585	$ 1,050
Purchased power - not commercially operable	—	—	7	7	7	146	167
Coal and natural gas	154	59	—	—	—	—	213
Transportation	78	58	30	30	29	108	333
Long-term service agreements	5	5	4	4	4	11	33
Capital projects	—	3	3	3	3	48	60
Operating leases	4	4	2	2	1	34	47
Total commitments	$ 335	$ 225	$ 144	$ 146	$ 121	$ 932	$ 1,903

Purchased Power

The Company has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2014 to 2039. While the Company is not required to make payment if power is not delivered under these contracts, estimated future payments are included in the tables above. Purchased power includes contracts which meet the definition of a lease. The Company's rent expense for purchase power contracts which met the lease criteria for 2013 and 2012 were $63 million and $60 million, respectively, and are recorded as cost of fuel, energy and capacity on the Statements of Income.

Purchased Power - Not Commercially Operable

The Company has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Coal and Natural Gas

The Company has several long-term contracts for the purchase of coal and natural gas. The expiration of these contracts range from 2014 to 2015.

Transportation

The Company has several long-term contracts for the transport of coal and natural gas. The expiration of these transportation contracts range from 2014 to 2030.

Long-Term Service Agreements

The Company has a long-term service agreement for the performance of maintenance on the Tracy Generating Station. Obligation amounts are based on estimated usage. The service agreements expires in 2020.

Operating Leases

The Company has various non-cancelable operating leases primarily for building, land and equipment. Contract expiration dates range from 2014 to 2103. Rent expense on non-cancelable operating leases totaled $5 million for 2013, $6 million for 2012.

Environmental Laws and Regulations

The Company is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Valmy Generation Station

In June 2009, the Company received a request for information from the Environmental Protection Agency Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for the Company's Valmy Generating Station located in Valmy, Nevada. The Company co-owns and operates this coal-fueled generating facility. Idaho Power Company owns the remaining 50%. The Environmental Protection Agency's Section 114 information request does not allege any incidents of non-compliance at the plant, and there have been no other new enforcement-related proceedings that have been initiated by the Environmental Protection Agency relating to the plant. The Company completed its response to the Environmental Protection Agency in December 2009 and will continue to monitor developments relating to this Section 114 request. At this time, the Company cannot predict the impact, if any, associated with this information request.

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its financial results. The Company 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.

Newmont Nevada Energy Investment - TS Power Plant

Newmont Nevada Energy Investment, LLC ("Newmont") owns a 203 megawatt coal-fired power plant facility located in Eureka County, NV (the "TS Power Plant") that is interconnected to the Company's transmission system. As a result of system modifications required for the ON Line, (a 500-kilovolt transmission line connecting the Company and Nevada Power Company, an electric utility wholly owned by NV Energy), Newmont will need to install certain protection equipment at its TS Power Plant. Newmont brought suit against the Company in the Second Judicial District of Nevada (Washoe County) seeking declaratory relief and to enjoin the operation at full capacity of certain equipment (series capacitors) to be installed by the Company for the ON Line project, until such time as Newmont completes the design, fabrication and installation of protection equipment at its power plant to protect its generator from potential adverse effects caused by the operation of the Company's equipment at full capacity. In addition, Newmont's complaint asserted a claim under the parties' interconnection agreement seeking to recover the cost of making the necessary modifications to the TS Power Plant.

A hearing on Newmont's motion for a preliminary injunction was held during the week of August 12, 2013, after which the trial court concluded that it would enter an order enjoining the Company from operating its equipment (series capacitors) at full capacity from

January 1, 2014 until approximately April 8, 2014, and from approximately June 1, 2014 to June 30, 2014 (or the time Newmont has completed the installation of its protection equipment), so as to allow installation and testing of protection equipment at the TS Power Plant. The district court issued the order on December 17, 2013. Newmont posted the required $1 million bond and subsequently filed a complaint with the Federal Energy Regulatory Commission in Docket No. EL14-16-000 to address the issue of who will pay for the protection equipment and the installation at the TS Power Plant. On April 9, 2014, the FERC issued an order directing the Company to pay the costs of studies relating to subsynchronous resonance conducted by Newmont and the installation of the protection equipment at the TS Power Plant, which are estimated to be $1 million and $11 million, respectively.

Caughlin Fire

On November 18, 2011, a fire was reported in the hills near Reno, Nevada (the "Caughlin Fire"). In January 2012, the Reno Fire Department issued a report in which they opined that "this fire was most likely the result of an electrical event in the area," and that "something such as a tree branch hitting the power-line" was a likely cause of the fire. The Company is continuing its investigation in the matter.

To date, six subrogation lawsuits and two individual claimant lawsuits have been filed against the Company in relation to the Caughlin Fire. The subrogation lawsuits have been brought by various insurance companies, and involve similar causes of action (negligence, inverse condemnation, trespass, nuisance, subrogation and strict liability). One of the individual claimant lawsuits identifies six plaintiffs, while the other individual claimant lawsuit purports to be brought on behalf of a class of similarly affected individuals within the fire perimeter who suffered damage or loss of use of their property as a result of the Caughlin Fire and the evacuation order associated with it.

All of the cases have been consolidated before a single judge in Washoe County, Nevada. The court has not yet entered a scheduling order in this case. At this time, management cannot assess or predict what the impact or outcome of this litigation may be, or what, if any, other litigation may be brought on this matter.

(15) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2013	2012
Supplemental disclosure of cash flow information -		
Interest paid, net of amounts capitalized	$ 59	$ 60
Supplemental disclosure of non-cash investing and financing transactions:		
Accruals related to property, plant and equipment additions	$ 37	$ 27
ON Line transmission use financial lease obligation	$ 22	$ —

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(1,384,149)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(164,037)		
4	Total (lines 2 and 3)		(164,037)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(1,548,186)		
6	Balance of Account 219 at Beginning of Current Year		(1,548,186)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(117,926)		
9	Total (lines 7 and 8)		(117,926)		
10	Balance of Account 219 at End of Current Quarter/Year		(1,666,112)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(1,384,149)		
2					
3			(164,037)		
4			(164,037)	84,354,523	84,190,486
5			(1,548,186)		
6			(1,548,186)		
7					
8			(117,926)		
9			(117,926)	55,341,892	55,223,966
10			(1,666,112)		

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	3,731,725,313	3,154,114,330
4	Property Under Capital Leases	23,797,678	23,797,678
5	Plant Purchased or Sold		
6	Completed Construction not Classified	14,100	14,100
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,755,537,091	3,177,926,108
9	Leased to Others		
10	Held for Future Use	8,907,652	6,776,239
11	Construction Work in Progress	88,869,338	76,280,622
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	3,853,314,081	3,260,982,969
14	Accum Prov for Depr, Amort, & Depl	1,519,672,250	1,269,469,260
15	Net Utility Plant (13 less 14)	2,333,641,831	1,991,513,709
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,449,787,080	1,268,636,741
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	68,892,658	
22	Total In Service (18 thru 21)	1,518,679,738	1,268,636,741
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	992,512	832,519
29	Amortization		
30	Total Held for Future Use (28 & 29)	992,512	832,519
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,519,672,250	1,269,469,260

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Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
367,577,501				210,033,482	3
					4
					5
					6
					7
367,577,501				210,033,482	8
					9
2,131,413					10
561,310				12,027,406	11
					12
370,270,224				222,060,888	13
152,346,370				97,856,620	14
217,923,854				124,204,268	15
					16
					17
152,186,377				28,963,962	18
					19
					20
				68,892,658	21
152,186,377				97,856,620	22
					23
					24
					25
					26
					27
159,993					28
					29
159,993					30
					31
					32
152,346,370				97,856,620	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
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			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	26,156	
3	(302) Franchises and Consents	100	
4	(303) Miscellaneous Intangible Plant	23,085,356	1,508,441
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	23,111,612	1,508,441
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,575,019	7,570
9	(311) Structures and Improvements	83,630,840	3,846,118
10	(312) Boiler Plant Equipment	245,105,451	15,517,171
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	93,126,912	-285,570
13	(315) Accessory Electric Equipment	48,134,124	-54,337
14	(316) Misc. Power Plant Equipment	9,861,094	1,753,811
15	(317) Asset Retirement Costs for Steam Production	6,629,038	804,583
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	488,062,478	21,589,346
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights	17,319	
38	(341) Structures and Improvements	38,444,473	1,946,884
39	(342) Fuel Holders, Products, and Accessories	113,870,536	73,637
40	(343) Prime Movers	22,338,253	
41	(344) Generators	307,287,032	1,936,636
42	(345) Accessory Electric Equipment	64,710,326	1,415,046
43	(346) Misc. Power Plant Equipment	34,457,367	1,322,011
44	(347) Asset Retirement Costs for Other Production	850,436	-88,450
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	581,975,742	6,605,764
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,070,038,220	28,195,110

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Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	50,614,241	-806,979
49	(352) Structures and Improvements	19,659,054	-133,654
50	(353) Station Equipment	209,141,580	8,875,588
51	(354) Towers and Fixtures	130,065,938	1,597,604
52	(355) Poles and Fixtures	80,200,615	306,754
53	(356) Overhead Conductors and Devices	155,792,453	-329,332
54	(357) Underground Conduit	9,121,361	-974,723
55	(358) Underground Conductors and Devices	12,555,063	
56	(359) Roads and Trails	383,112	63,613
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	667,533,417	8,598,871
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	12,726,782	74,672
61	(361) Structures and Improvements	3,403,132	8,931
62	(362) Station Equipment	182,578,687	5,532,014
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	144,277,015	9,292,117
65	(365) Overhead Conductors and Devices	134,491,012	8,077,569
66	(366) Underground Conduit	77,293,756	2,195,359
67	(367) Underground Conductors and Devices	305,684,508	6,897,191
68	(368) Line Transformers	182,217,188	12,546,717
69	(369) Services	117,117,810	5,106,823
70	(370) Meters	51,221,057	3,036,554
71	(371) Installations on Customer Premises	7,388,902	89,100
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	36,623,589	2,575,829
74	(374) Asset Retirement Costs for Distribution Plant	754,998	532,879
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,255,778,436	55,965,755
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	363,645	9,916
87	(390) Structures and Improvements	9,039,712	1,686,535
88	(391) Office Furniture and Equipment	7,996,966	337,962
89	(392) Transportation Equipment	5,103,463	
90	(393) Stores Equipment	60,257	
91	(394) Tools, Shop and Garage Equipment	2,108,618	1,235,110
92	(395) Laboratory Equipment	785,201	
93	(396) Power Operated Equipment	2,156,515	8,558
94	(397) Communication Equipment	49,822,286	13,593,040
95	(398) Miscellaneous Equipment	52,782	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	77,489,445	16,871,121
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	-871	-10,209
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	77,488,574	16,860,912
100	TOTAL (Accounts 101 and 106)	3,093,950,259	111,129,089
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,093,950,259	111,129,089

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			26,156		2
			100		3
1,807,403		-592,207	22,194,187		4
1,807,403		-592,207	22,220,443		5
					6
					7
			1,582,589		8
4,407,313			83,069,645		9
5,933,148			254,689,474		10
					11
1,249,670			91,591,672		12
41,421		178,061	48,216,427		13
389,327			11,225,578		14
			7,433,621		15
12,020,879		178,061	497,809,006		16
					17
					18
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					34
					35
					36
			17,319		37
29,007			40,362,350		38
			113,944,173		39
2,147,039			20,191,214		40
2,348,436			306,875,232		41
532,137			65,593,235		42
1,116,614			34,662,764		43
			761,986		44
6,173,233			582,408,273		45
18,194,112		178,061	1,080,217,279		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			49,807,262		48
43,772			19,481,628		49
1,452,598		-178,061	216,386,509		50
66,257			131,597,285		51
48,921		-35,786	80,422,662		52
69,009		-11,925	155,382,187		53
			8,146,638		54
			12,555,063		55
			446,725		56
					57
1,680,557		-225,772	674,225,959		58
					59
			12,801,454		60
38,914			3,373,149		61
919,037		2,067	187,193,731		62
					63
806,341		4,820,906	157,583,697		64
1,261,813		-3,178,155	138,128,613		65
1,517,467		-2,067	77,969,581		66
1,540,415			311,041,284		67
2,350,748		-1,595,040	190,818,117		68
154,970			122,069,663		69
16,987,053			37,270,558		70
8,246			7,469,756		71
					72
564,199			38,635,219		73
			1,287,877		74
26,149,203		47,711	1,285,642,699		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
3			373,558		86
17,898		-212,681	10,495,668		87
884,406		-8,731	7,441,791		88
57,009		27,330	5,073,784		89
5,482			54,775		90
319,728			3,024,000		91
			785,201		92
			2,165,073		93
1,208,502		145,573	62,352,397		94
			52,782		95
2,493,028		-48,509	91,819,029		96
					97
			-11,080		98
2,493,028		-48,509	91,807,949		99
50,324,303		-640,716	3,154,114,329		100
					101
					102
					103
50,324,303		-640,716	3,154,114,329		104

Schedule Page: 204 Line No.: 12 Column: c

Reclassification of FERC account due to final unitization.

Schedule Page: 204 Line No.: 13 Column: c

Reclassification of FERC account due to final unitization.

Schedule Page: 204 Line No.: 44 Column: c

Asset retirement obligation.

Schedule Page: 204 Line No.: 48 Column: c

Reclassification of FERC account due to final unitization.

Schedule Page: 204 Line No.: 49 Column: c

Reclassification of FERC account due to final unitization.

Schedule Page: 204 Line No.: 53 Column: c

Reclassification of FERC account due to final unitization.

Schedule Page: 204 Line No.: 54 Column: c

Reclassification of FERC account due to final unitization.

Schedule Page: 204 Line No.: 98 Column: c

Asset retirement obligation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	None				
2					
3					
4					
5					
6					
7					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4				
5				
6				
7				
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9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Fiber optics (media conduit)	12/1/1999		3,136,902
23	Distribution station transformer	12/1/2010		142,027
24	Red Rock Substation	12/1/2013		3,497,310
25				
26				
27				
28				
29				
30				
31				
32				
33				
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35				
36				
37				
38				
39				
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46				
47	Total			6,776,239

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BORDERTOWN TO CAL SUB LAND RIGHTS	1,069,178
2	VALMY 2 SCRUBBER SPRAY MACHINES	1,128,754
3	VALMY COMMON MIXED BED DEMINERALIZER REPLACEMENT	1,256,284
4	VALMY 2 SCRUBBER REAGENT AND OPTIMIZATION PROJECT	1,354,627
5	BORDERTOWN TO CAL SUB 120kV	1,408,972
6	NORTH VALLEY ROAD CAPICITOR BANK ADDITION AIR EMMISSIONS	1,484,835
7	TRACY 3 BEST AVAILABLE RETROFIT TECHNOLOGY	1,613,479
8	VALMY 1 SOOTBLOWER SYSTEM REPLACEMENT	1,656,747
9	MIRA LOMA 345KV CAPACITOR BANK ADDITIONS	1,665,553
10	TRACY COMMON WATER BALANCE MODIFICATION	1,745,627
11	TRACY 4 STAGE 1 BUCKETS	2,195,384
12	VALMY COMMON CAUSTIC TANK BUILDING REPLACEMENT	2,200,945
13	VALMY COMMON DUST COLLECTOR	2,907,919
14	VALMY 1 UTILITY MERCURY AND AIR TOXIC STANDARDS	2,953,240
15	FALCON SUBSTATION SERIES CAPACITORS	3,329,292
16	FORT CHURCHILL 2 BEST AVAILABLE RETROFIT	3,395,414
17	FORT CHURCHILL 1 TECHNOLOGY AIR EMMISSIONS RULES	3,636,346
18	EWAM 2.2 IMPLEMENTATION	10,544,427
19	PROJECTS UNDER $1,000,000	30,733,599
20		
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22		
23		
24		
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29		
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43	TOTAL	76,280,622

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,228,520,447	1,227,837,035	683,412	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	73,564,918	73,564,918		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,468,691	1,468,691		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	325,642	325,642		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	1,559,413	1,370,907	188,506	
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	76,918,664	76,730,158	188,506	
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	50,324,303	50,324,303		
13	Cost of Removal	3,733,612	3,733,612		
14	Salvage (Credit)	121,802	121,802		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	53,936,113	53,936,113		
16	Other Debit or Cr. Items (Describe, details in footnote):	17,966,262	18,005,661	-39,399	
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,269,469,260	1,268,636,741	832,519	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	348,083,046	348,083,046		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	126,301,440	126,301,440		
25	Transmission	218,530,761	218,530,761		
26	Distribution	529,410,785	529,410,785		
27	Regional Transmission and Market Operation				
28	General	47,143,228	46,310,709	832,519	
29	TOTAL (Enter Total of lines 20 thru 28)	1,269,469,260	1,268,636,741	832,519	

Schedule Page: 219 Line No.: 3 Column: c

Does not include allocated common plant depreciation expense of $5,354,105.

Schedule Page: 219 Line No.: 8 Column: c

Account 404 amortization of Electric intangible plant. Does not include common plant allocation of amortization expense of $ 10,457,310.

Schedule Page: 219 Line No.: 8 Column: d

Plant held for future use depreciation is charged to account 421000

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

Adjustments and transfers.

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

Adjustments and transfers PHFFU.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	29,337,730	11,638,247	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	25,132,944	23,428,094	Electric/Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,708,173	3,647,080	Electric
8	Transmission Plant (Estimated)	62,157	109,937	Electric
9	Distribution Plant (Estimated)	1,560,289	2,536,958	Electric/Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	29,463,563	29,722,069	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	522,609	76,317	Electric/Gas
17				
18	Liquefied Natural Gas (Account 16	1,337,609	1,233,837	Gas
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	60,661,511	42,670,470	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains	188.50	27		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
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								41
								42
								43
								44
				188.50	4	377.00	31	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2015		2016		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	None					
2						
3						
4						
5						
6						
7						
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9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	None					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
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42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Gradient SIS Patua II	12,424	186201	30,000	186201
3	ORNI 47 Gonder SIS #1	5,893	186201	60,000	186201
4	ORNI 47 Gonder Facilities Study #1	3,145	186201		186201
5	ORNI 47 Gonder SIS #2	4,282	186201	60,000	186201
6	ORNI 47 Gonder Facilities Study #2	1,977	186201		186201
7	ORNI 39 Hilltop SIS	10,569	186201	60,000	186201
8	ORNI 39 Hilltop Facilities Study	17,603	186201		186201
9	ORNI 39 Gonder SIS	6,311	186201	60,000	186201
10	ORNI 39 Gonder Facilities Study	3,306	186201		186201
11	ORNI 43 Gonder SIS #1	5,847	186201	30,000	186201
12	ORNI 43 Gonder Facilities Study #1	10,569	186201		186201
13	ORNI 43 Hilltop SIS #1	9,592	186201	33,697	186201
14	ORNI 43 Hilltop Facilities Study 1	14,681	186201		186201
15	ORNI 43 Gonder SIS #2	3,078	186201	30,000	186201
16	ORNI 43 Hilltop SIS #2	2,748	186201	60,000	186201
17	ORNI 47 LLC Gonder SIS #1	9,734	186201	60,000	186201
18	ORNI 47 LLC GonderSIS #2	11,402	186201	30,000	186201
19	Barrick SIS #1	15,029	186201	10,000	186201
20	Barrick SIS #2	2,990	186201	10,000	186201
21	**Generation Studies**				
22	Company EO Facilities Study	8,170	186201		186201
23	Company ET Facilities Study	15,101	186201		186201
24	Company EU Facilities Study	7,242	186201		186201
25	Company EV Facilities Study	15,808	186201		186201
26	Company EY Facilities Study	9,735	186201		186201
27	Company FA Facilties Study	10,814	186201		186201
28	Company FK SIS	21,905	186201	75,000	186201
29	Company FP Feasibility Study	1,633	186201		186201
30	Company FQ SIS	2,920	186201	100,000	186201
31	Company FQ Facilities Study	8,780	186201		186201
32	Company FR SIS	22,176	186201	25,000	186201
33	Company FS SIS	13,241	186201	26,000	186201
34	Company FT SIS	12,464	186201	26,000	186201
35	Company FU SIS	4,654	186201	85,000	186201
36	Company FV SIS	4,279	186201	85,000	186201
37	Company FW SIS	6,869	186201	85,000	186201
38	Company FX SIS	5,504	186201	41,000	186201
39	Company FY SIS	1,314	186201	1,000	186201
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Valmy AFUDC Adj Amort. Pd 11/85-11/20	1,107,796		407	139,932	967,864
2	Utah Power Co. Fixed Charges Amort Pd 5/88-6/17	144,523		557	32,116	112,407
3	PG&E Intertie Reconductor Dkt. 91-7079	240,035		566	13,092	226,943
4	Amort Pd 1/96-4/31					
5	PG&E Intertie Dkt. 91-7079	369,383		566	23,831	345,552
6	Amort Pd 7/92-11/28					
7	Merger Goodwill Dkt. 03-12002/05-10005	91,509,150		930	2,883,950	88,625,200
8	Amort Pd 6/04-5/46					
9	Merger Severance/Relocation Dkt. 13-06002/3	1,875,749		920/926	1,101,924	773,825
10	Amort Pd 1/14-12/16					
11	Merger Transition-Transaction Dkt. 13-06002/3	1,966,935		930	1,118,620	848,315
12	Amort Pd 1/14-12/16					
13	Piñon Pine Combined Cycle Dkt 03-12002	25,805,113		407	1,571,885	24,233,228
14	Amort Pd 06/04-05/29					
15	Piñon Pine Gasifier Dkt 13-06002	1,996,354		407/419	1,531,695	464,659
16	Amort Pd 1/14-12/16					
17	Piñon Pine Hot Gas System Dkt. 10-06001	1,840,893	60,375	407	1,901,268	
18	Amort Pd 1/11-12/13					
19	Divestiture Costs Dkt. 10-06001	812,303		930	812,303	
20	Amort Pd 1/11-12/13					
21	2009 Severance programs Dkt. 10-06001/2	1,341,427		407	1,341,427	
22	Amort Pd 1/11-12/13					
23	Generation Studies Dkt. 10-06001	763,944		407	763,944	
24	Amort Pd 1/11-12/13					
25	Generation Obsolete Inventory Dkt. 10-06001	255,342		548	255,342	
26	Amort Pd 1/11-12/13					
27	Ely Energy Center Dkt Nos 11-06006/13-06002	11,544,084	16,654	506	1,500,000	10,060,738
28	Amort Pd 1/14-12/16					
29	Generation Life Assessment Dkt. 10-06001	71,741		407	71,741	
30	Amort Pd 1/11-12/13					
31	Diesel Units Net Book Value/Decommissioning	97,704	297,541	403/407	334,665	60,580
32	Dkt. Nos. 13-06002 Amort Pd 1/14-12/16					
33	BTGR Impact Dkt 13-06002 Amort Pd 1/14-12/16	4,322,890	183,190	456	2,075,002	2,431,078
34	BU 1245 OPEB Buy-Down Dkt. 10-06001/2	5,625,360		926	1,250,080	4,375,280
35	Amort Pd 7/08-6/17					
36	Regulatory Deferred Income Taxes	100,481,764	6,554,516	282/283	10,689,866	96,346,414
37	Indus Licensing Fees Dkt. 10-06001	2,000,000		903	2,000,000	
38	Kerotest Gas Valve Remediation	668,498	1,558,098			2,226,596
39	Dkt Nos 11-12020/13-06003 Amort pd 1/14-12/16					
40	Idlewild Master Meter Project Dkt 13-05060		113,845			113,845
41	Deferred Risk Management		13,124,119			13,124,119
42	NVEnergize Project Dkt. 10-03023/13-06002/3	2,692,359	21,385,485			24,077,844
43	Emma/Blackhawk Dkt 13-06002 Amort pd 1/14-12/16		15,218,000			15,218,000
44	TOTAL	290,411,518	95,317,836		77,959,103	307,770,251

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Energy Efficiency Programs Dkt. 13-03004/13-06002	15,357,859	3,608,124	254/908	17,504,458	1,461,525
3	various amortization periods					
4	Renewable Energy Programs Dkt. 13-03004	14,224,526	6,690,757	254/557	20,915,283	
5	various annual amortization periods					
6	Energy Efficiency Implementation Dkt. 13-03004	3,295,786	4,958,686	440-444	8,126,679	127,793
7	various annual amortization periods			254/426		
8	Cancelled IRP Projects		9,101,561			9,101,561
9	Union Pacific Damages		525,000			525,000
10	Deferred Energy Dkt. 13-03004		11,921,885			11,921,885
11	various annual amortization periods					
12						
13						
14						
15						
16						
17						
18						
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20						
21						
22						
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39						
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42						
43						
44	TOTAL	290,411,518	95,317,836		77,959,103	307,770,251

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Obsolete Inventory	336,547	1,533,007	various	1,869,554	
2	Advanced Service Delivery Prog	1,143,938	654,574			1,798,512
3	MTM Asset Deferral		387,800	175/254	387,800	
4	Pension Plan	140,268,220	1,729,689	219/228	53,313,427	88,684,482
5				926		
6	LTD Continuation Benefits	158,526	462,642			621,168
7	Asset Retirement Obligations	8,190,728	2,156,516	403	172	10,347,072
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47	Misc. Work in Progress	10,736,886				2,299,185
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	160,834,845				103,750,419

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	General Accounting Reserve	227,500	8,382,500
3	FAS 109	4,277,536	8,783,731
4	Customer Advances (Refundable)	5,193,061	5,215,411
5	Grossups on CIAC, Customer Advances, Trenching	5,140,204	5,048,720
6	Net Operation Loss (Federal & State)	59,966,542	63,955,114
7	Other	41,586,706	35,250,382
8	TOTAL Electric (Enter Total of lines 2 thru 7)	116,391,549	126,635,858
9	Gas		
10			
11	FAS 109	488,231	455,145
12	Customer Advances (Refundable)	1,046,028	996,007
13	Grossups on CIAC, Customer Advances, Trenching	484,658	415,909
14			
15	Other	6,316,668	3,879,162
16	TOTAL Gas (Enter Total of lines 10 thru 15	8,335,585	5,746,223
17	Valuation Allowance		-820,747
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	124,727,134	131,561,334

Notes

Schedule Page: 234 Line No.: 7 Column: a

	Balance at Beginning of Year	Balance at End of Year
Detail of Electric - Other (Line 7)		
Bad Debt Reserve	$ 220,360	$ 213,870
Benefits	32,104,603	9,253,946
Capital Lease Liability	-	8,336,012
Deferred land gains/amortizations	777,649	-
Ely Energy Center Water Rights & Farm	-	525,000
Injuries and Damages reserve	706,147	802,225
Interest Rate Swap - Gain Amort	4,118,171	3,536,084
Mark to Market	-	4,593,442
MEHC Merger Refund	-	1,615,729
Regulatory Liabilities	1,657,546	4,509,590
TRED Trust Reserve	2,002,225	1,864,478
Other	5	6
Total Electric - Other (Line 7)	$ 41,586,706	$ 35,250,382

Schedule Page: 234 Line No.: 15 Column: a

	Balance at Beginning of Year	Balance at End of Year
Detail of Gas - Other (Line 15)		
Bad Debt Reserve	$ 173,512	$ 186,428
Benefits	6,401,830	2,959,950
Injuries and Damages reserve	(289,887)	(289,824)
MEHC Merger Refund	-	133,105
Regulatory Liabilities	31,212	889,503
Other	1	-
Total Gas - Other (Line 15)	$ 6,316,668	$ 3,879,162

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common	20,000,000	3.75	
2				
3				
4				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,000	3,750					1
						2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account #211	
2		
3	Miscellaneous Paid in Capital	
4	- Investment of additional capital by parent company	
5	NV Energy, Inc.	920,771,103
6		
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40	TOTAL	920,771,103

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	None	
2		
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22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 - Long Term Debt Secured by General and Refunding Bonds:		
2	Pollution Control Refunding Revenue Bond Series 2006 Variable	49,750,000	1,115,368
3	Gas Facilities Refunding Revenue Bond Series 2006A Variable	58,700,000	1,857,966
4	Water Facilities Refunding Revenue Bond Series 2006B Variable	75,000,000	2,379,733
5	Gas and Water Facilities Refunding Revenue Bond Series 2006C Variable	84,800,000	3,461,359
6	Water Facilities Refunding Revenue Bond Series 2007A	40,000,000	1,262,236
7	Water Facilities Refunding Revenue Bond Series 2007B	40,000,000	1,133,112
8	Debt in lines 3-8 approved by the PUCN in Dkt. 05-10024 2/06		
9	Subtotal Acct. #221	348,250,000	11,209,774
10	Account 222 - Reaquired Bonds		
11	Reacq Series 2007B	-40,000,000	-1,133,112
12	Reacq Series 2006	-49,750,000	-1,115,368
13	Reacq Series 2007A	-40,000,000	-1,262,236
14	Reacq Series 2006A	-500,000	-16,722
15	Reacq Series 2006C	-3,325,000	-134,993
16	Subtotal Acct. #222	-133,575,000	-3,662,431
17	Account #224 - Other Long -Term Debt		
18	Debt Secured by General and Refunding Bonds:		
19	Series S (Wells Fargo Bank Credit Agreement)		1,447,152
20	PUC of Nevada order #09-07024		
21	General and Refunding Mortgage Notes Series M 6% Approved in Dkt. 05-10024 02/06	450,000,000	6,500,280
22			398,094 D
23			-9,256,500 P
24	General and Refunding Mortgage Notes Series P 6.75% Approved in Dkt. 05-10024 02/06	325,000,000	4,546,105
25			87,750 D
26			-11,281,215 P
27	General and Refunding Mortgage Notes Series Q 5.45% Approved in Dkt. 07-03005 06/07	250,000,000	1,967,446
28			850,727 D
29	General and Refunding Mortgage Notes Series T 3.375% Approved in Dkt.12-07002 11/12	250,000,000	1,976,075
30			525,000 D
31	Subtotal-Acct. #224	1,275,000,000	-2,239,086
32			
33	TOTAL	1,489,675,000	5,308,257

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
11/22/06	10/01/29	11/22/06	10/01/29	49,750,000		2
11/22/06	08/01/31	11/22/06	08/01/31	58,700,000	456,132	3
11/22/06	03/01/36	11/22/06	03/01/36	75,000,000	589,298	4
11/22/06	03/01/36	11/22/06	03/01/36	84,800,000	625,578	5
04/27/07	03/01/36	04/27/07	03/01/36	40,000,000		6
04/27/07	03/01/36	04/27/07	03/01/36	40,000,000		7
						8
				348,250,000	1,671,008	9
						10
				-40,000,000		11
				-49,750,000		12
				-40,000,000		13
				-500,000		14
				-3,325,000		15
				-133,575,000		16
						17
						18
03/23/12	03/23/17	03/23/12	03/23/17			19
						20
03/23/06	05/15/16	03/23/06	05/15/16	450,000,000	27,000,000	21
						22
						23
06/28/07	07/01/37	06/28/07	07/01/37	251,742,000	16,992,585	24
						25
						26
09/02/08	09/01/13	09/02/08	09/01/13		9,083,333	27
						28
08/15/13	08/15/23	08/15/13	08/15/23	250,000,000	3,164,063	29
						30
				951,742,000	56,239,981	31
						32
				1,166,417,000	57,910,989	33

Schedule Page: 256 Line No.: 11 Column: b

SPPC purchased 100% of the $40M Water Facilities Refunding Revenue Bonds Series 2007B in July 2008 and are the sole holders of the Bonds until such time as SPPC determines to reoffer the Bonds to investors. The Bonds remain outstanding and have not been retired or cancelled. Original debt expense amortization costs on reacquired bonds are reported in account 189.

Schedule Page: 256 Line No.: 12 Column: b

SPPC purchased 100% of the $49.75M Pollution Control Refunding Revenue Bonds Series 2006 in October 2008 and are the sole holder of the Bonds until such time as SPPC determines to reoffer the Bonds to investors. The Bonds remain outstanding and have not been retired or cancelled. Original debt expense amortization costs on reacquired bonds are reported in account 189.

Schedule Page: 256 Line No.: 13 Column: b

SPPC purchased 100% of the $40M Water Facilities Refunding Revenue Bonds Series 2007A in January 2009 and are the sole holder of the Bonds until such time as SPPC determines to reoffer the Bonds to investors. The Bonds remain outstanding and have not been retired or cancelled. Original debt expense amortization costs on reacquired bonds are reported in account 189.

Schedule Page: 256 Line No.: 14 Column: b

SPPC purchased 0.9% of the $58.7M Pollution Control Refunding Revenue Bonds Series 2006A in October 2009. The repurchased Bonds remain outstanding and have not been retired or cancelled. Original debt expense amortization costs on reacquired bonds are reported in account 189.

Schedule Page: 256 Line No.: 15 Column: b

SPPC purchased 3.9% of the $84.8M Pollution Control Refunding Revenue Bonds Series 2006C in October 2009. The repurchased Bonds remain outstanding and have not been retired or cancelled. Original debt expense amortization costs on reacquired bonds are reported in account 189.

Schedule Page: 256 Line No.: 19 Column: b

Series S Credit Facility is considered long-term debt due to the expiration date of March 2017. The facility authorizes borrowings up to $250 million; as of 12/31/13, total amount outstanding on the credit facility was $0.

Schedule Page: 256 Line No.: 24 Column: b

$73,258,000 of original $325,000,000 redeemed December 2009.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	55,341,892
2		
3		
4	Taxable Income Not Reported on Books	
5	Deferred Conservation Programs	61,669,411
6	Grossups on CIAC, Customer Advances, Trenching	2,409,550
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Income Tax Expense	32,930,734
11	Other Expenses on Books Not Deducted (See Footnote)	104,938,092
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Amortization of Gross-Ups	-2,867,357
16	Customer Advances	-79,057
17	Land Gains/Amortization	-2,221,854
18		
19	Deductions on Return Not Charged Against Book Income	
20	Deferred Fuel - Residential	-67,442,069
21	Depreciation & Property Related	-79,858,769
22	Other Deductions on Return Not in Books (See Footnote)	-128,326,397
23		
24		
25		
26		
27	Federal Tax Net Income	-23,505,824
28	Show Computation of Tax:	
29		
30	Federal Tax at 35%	-8,227,038
31		
32	Transfer Payable to Net Operating Loss	8,227,038
33	Research and Development Credit	-245,680
34	Transfer FIN48 Liability to NOL	-2,253,826
35	Total Federal Tax Expense Recorded	-2,499,506
36		
37		
38	Operating (Account 409100)	-2,211,315
39	Nonoperating (Account 409200)	-288,191
40	Total Federal Tax Expense Recorded in F/S	-2,499,506
41		
42		
43		
44		

Schedule Page: 261 Line No.: 11 Column: a

Other Deductions Recorded on Books		
Bond redemp & amort	$	2,469,612
Capital Leases		19,498
Ely Energy Center Water Rights & Farm		1,500,000
General accounting reserve		23,300,000
Goodwill		2,883,948
Injuries & Damages		274,689
MEHC Merger Related Expenses		13,328,525
Miscellaneous Perm Expenses		1,191,475
Provision for Rate Refund		110,616
Regulatory Asset - Pension Plan (FAS158)		51,502,790
Regulatory Liabilities		8,338,580
Reserve for Bad Debts		18,359
Total Other Deductions Recorded on Books	$	104,938,092

Schedule Page: 261 Line No.: 22 Column: a

Other Deductions on Return Not Charged Against Books		
Benefits	$	(76,897,776)
Caughlin Ranch Insurance Reserve		(23,300,000)
Mark to Market		(1,187,964)
Regulatory Assets		(25,790,987)
Research and Development Credit		(1,149,670)
Total Other Deductions on Return Not Charged Against Books	$	(128,326,397)

Schedule Page: 261 Line No.: 27 Column: b

NV Energy, Inc. was acquired by Berkshire Hathway Inc. on 12/19/2013. Berkshire Hathaway Inc. includes NV Energy, Inc. in its United States Federal Income Tax Return for the period of 12/20/2013 - 12/31/2013. A separate stub period return will be filed for NV Energy, Inc. for the period of 1/1/2013 - 12/19/2013. NV Energy Inc.'s provision for income taxes has been computed on a separate return basis.

Names of group members who will file a consolidated United States Federal Income Tax Return for the period 1/1/2013 - 12/19/2013:

NV Energy, Inc. Sub-Group

Commonsite, Inc.	NVE Holdings, LLC
GPSF-B	NVE Insurance Co, Inc.
Lands of Sierra, Inc.	Pinon Pine Corporation
Nevada Electric Investment Company	Pinon Pine Investment Company
Nevada Power Company dba NV Energy	Sierra Gas Holding Company
NV Energy, Inc. fka Sierra Pacific Resources	Sierra Pacific Power Company dba NV Energy

Names of group members who will file a consolidated United States Federal Income Tax Return for the period 12/20/2013 - 12/31/2013:

Under NV Energy, Inc. ("NVE")"
NVE Holdings Sub-Group:

NV Energy, Inc.
NVE Holdings, LLC

NV Energy, Inc. Sub-Group

Commonsite, Inc.	NVE Holdings, LLC
GPSF-B	NVE Insurance Co, Inc.
Lands of Sierra, Inc.	Pinon Pine Corporation
Nevada Electric Investment Company	Pinon Pine Investment Company
Nevada Power Company dba NV Energy	Sierra Gas Holding Company
NV Energy, Inc. fka Sierra Pacific Resources	Sierra Pacific Power Company dba NV Energy

MEHC Sub-Group:

Alaska Gas Transmission Company, LLC
American Pacific Finance Company
American Pacific Finance Company II
AVSP 1B, LLC
AVSP 2B, LLC
BG Energy Holding Company LLC
BG Energy LLC
Bishop Hill Energy II, LLC
Bishop Hill II Holdings, LLC
CalEnergy Company, Inc
CalEnergy Generation Operating Company
CalEnergy Holdings, Inc
CalEnergy International Services, Inc
CalEnergy International, Inc
CalEnergy Minerals Development, LLC
CalEnergy Minerals LLC
CalEnergy Pacific Holdings Corp
CalEnergy UK Inc
CE Administrative Services, Inc
CE Black Rock Holdings LLC
CE Butte Energy Holdings LLC
CE Butte Energy LLC
CE Electric (NY), Inc
CE Electric, Inc
CE Exploration Company
CE Geothermal, Inc.
CE Indonesia Geothermal, Inc
CE International Investments, Inc
CE Obsidian Energy LLC
CE Obsidian Holding LLC
CE Power, Inc
CE Red Island Energy Holdings LLC
CE Red Island Energy LLC
Cordova Energy Company, LLC
Cordova Funding Corporation
M & M Ranch Acquisition Company LLC
M & M Ranch Holding Company LLC
MEHC American Transco LLC
MEHC Canada, LLC
MEHC Insurance Services Ltd.
MEHC Investment, Inc
MEHC Merger Sub Inc
MEHC Texas Transco LLC
MidAmerican AC Holding, LLC
MidAmerican Energy Holdings Company
MidAmerican Energy Machining Services LLC
MidAmerican Funding, LLC
MidAmerican Geothermal, LLC
MidAmerican Hydro, LLC
MidAmerican Nuclear Energy Company LLC
MidAmerican Renewables, LLC
MidAmerican Solar, LLC
MidAmerican Transmission, LLC
MidAmerican Wind, LLC
Midwest Power Transmission Illinois LLC
Midwest Power Transmission Iowa LLC
NNGC Acquisition LLC
Northern Aurora Inc
Pinyon Pines I Holding Company, LLC
Pinyon Pines II Holding Company, LLC
Pinyon Pines Wind I, LLC
Pinyon Pines Wind II, LLC

Solar Star 3, LLC
Solar Star California XIX, LLC
Solar Star California XX, LLC
Solar Star Funding, LLC
Solar Star Projects Holdings, LLC
SSC XIX, LLC
SSC XX, LLC
Topaz Solar Farms, LLC
TPZ Holding, LLC
Wailuku Investment LLC
Kern River Funding Corporation
KR Acquisition 1, LLC
KR Acquisition 2, LLC
KR Holding, LLC
Cimmred Leasing Company
Dakota Dunes Development Company
DCCO, Inc
MEC Construction Services Company
MHC Investment Company
MHC, Inc
MidAmerican Energy Company
Midwest Capital Group, Inc
MWR Capital, Inc
Two Rivers, Inc
Northern Natural Gas Company
Centralia Mining Company
Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc
PacifiCorp
PPW Holdings LLC
Commonsite, Inc.
GPSF-B
Lands of Sierra, Inc.
Nevada Electric Investment Company
Nevada Power Company dba NV Energy
NV Energy, Inc. fka Sierra Pacific Resources
NVE Holdings, LLC
NVE Insurance Co, Inc.
Pinon Pine Corporation
Pinon Pine Investment Company
Sierra Gas Holding Company
Sierra Pacific Power Company dba NV Energy
Arizona HomeServices, LLC
Capitol Title Company
CBSHome Commerical, LLC
CBSHome Real Estate Company
CBSHome Real Estate of Iowa, Inc
CBSHome Relocation Services, Inc
Champion Realty, Inc
Chancellor Title Services, Inc
Columbia Title of Florida, Inc
Connecticut Referral Group, L.L.C.
CTHM, L.L.C.
CTRE, L.L.C.
Edina Financial Services, Inc
Edina Realty Referral Network, Inc
Edina Realty Relocation, Inc
Edina Realty Title, Inc
Edina Realty, Inc
Employee Transfer Corporation

F&R/T LLC
FFR, Inc
First Realty, Ltd
First Reserve Insurance, Inc
For Rent, Inc
FRTC, LLC
Guarantee Appraisal Corporation
Guarantee Real Estate
HMSV Financial Services, Inc
HN Real Estate Group N.C., Inc
HN Real Estate Group, LLC
HN Referral Corporation
HomeServices Financial Holdings, Inc
HomeServices Insurance, Inc
HomeServices Northeast, LLC
HomeServices of Alabama, Inc.
HomeServices of America, Inc
HomeServices of California, Inc
HomeServices of Connecticut, LLC
HomeServices of Florida, Inc
HomeServices of Georgia, LLC
HomeServices of Iowa, Inc
HomeServices of Kentucky, Inc
HomeServices of Nebraska, Inc
HomeServices of Oregon, LLC
HomeServices of the Carolinas, Inc
HomeServices of Washington, LLC
HomeServices Referral Network, LLC
HomeServices Relocation, LLC
HomeSvc of IL LLC d/b/a Koenig & Strey GMAC RE
HS Franchise Holding, LLC
HSGA Real Estate Group, L.L.C.
HSR Equity Funding, Inc
Huff Commercial Group, LLC
Huff-Drees Realty, Inc
IMO Company, Inc
InsuranceSouth, LLC
Iowa Realty Company, Inc
Iowa Realty Insurance Agency, Inc
Iowa Title Company
J.S. White Associates, Inc
JBRC, Inc
Jim Huff Realty, Inc.
JRHBW Realty, Inc d/b/a/ RealtySouth
Kansas City Title, Inc
Kentucky Residential Referral, LLC
Larabee School of Real Estate & Insurance, Inc
Mid-America Referral Network, Inc.
Midland Escrow Services, Inc
Midwest Realty Ventures, LLC
Nebraska Land Title & Abstract Company
Nebraska Referral, Inc.
NMA, LLC
NRS Referral Services, LLC
NW Referral Services, LLC
PCRE, L.L.C.
PFR Staffers, LLC
Pickford Escrow Company, Inc
Pickford Holdings, LLC
Pickford Real Estate, Inc
Pickford Services Company, Inc
Pilot Butte, LLC

Quad Cities Energy Company	Esslinger-Wooten-Maxwell, Inc	PNW Referral, LLC
Salton Sea Minerals Corporation	E-W-M Referral Services, Inc.	PPW Staffers, LLC
Preferred Carolinas Realty, Inc	Reece Commercial, Inc.	Semonin Realtors, Inc
Preferred Carolinas Title Agency, LLC	Referral Associates of Georgia, LLC	Southwest Relocation, LLC
Professional Referral Organization, Inc	Referral Company of North Carolina, Inc	Sterling Title Services, LLC
PW Fox Holding LLC	Referral Network of IL LLC	The Escrow Firm
PW Fox, LLC	Relocation Advantage Partners, LLC	The Referral Company
Real Estate Knowledge Services, L.L.C.	RHL Referral Company, LLC	TIAC LLC
Real Estate Links, LLC	Roberts Brothers, Inc	TitleSouth, LLC
Real Estate Referral Network, Inc	Roy H. Long Realty Company, Inc	TLTC LLC
Reece & Nichols Alliance, Inc	Rubloff Insurance Agency LLC	TRMC LLC
Reece & Nichols Realtors, Inc	San Diego PCRE, Inc	Wm Broughton, LLC

All Other Affiliates:

Berkshire Hathaway Inc.	Los Angeles Junction Railway Company	CTB International Corp
Berkshire Hathaway Credit Corporation	Star Lake Railroad Company	Ironwood Plastics Inc
Berkshire Hathaway Finance Corporation	The BN and SF Railway de Mexico, S.A. de C.V.	CTB IW INC
BH Columbia Inc.	The Zia Company	CTB Midwest
Railsplitter Holdings Corporation	Santa Fe Pacific Pipeline Holdings, Inc.	CTB MN Investments
Acme Brick Company	Burlington Northern Santa Fe British Columbia, Ltd.	Meyn LLC
Acme Brick DFW, Inc.	Pine Canyon Land Company	International Dairy Queen, Inc.
Acme Brick Sales Company	Santa Fe Pacific Insurance Company	American Dairy Queen Corporation
Acme Ochs Brick and Stone, Inc.	Santa Fe Pacific Railroad Company	DQF, Inc.
American Tile and Stone, Inc	Western Fruit Express Company	DQGC, Inc.
Innovative Building Products, Inc	Burlington Northern Railroad Holdings, Inc.	Unified Supply Chain, Inc.
Alpha Cargo Motor Express, Inc	Winona Bridge Railroad Company	DQ Funding Corporation
Brick Acquisition Company	BNSF Railway International Services, Inc.	Dairy Queen Of Georgia, Inc.
Acme Building Brands, Inc	BN Leasing Corporation	Golden Skillet International, Inc.
Acme Investment Company	Midwest Northwest Properties, Inc.	Karmelkorn Shoppes, Inc.
Acme Management Company	Santa Fe Pacific Pipelines, Inc.	Orange Julius Of America
Acme Services Company, L.P.	BNSF Communications, Inc.	Dairy Queen Corporate Stores, Inc.
Denver Brick Company	BNSF Spectrum, Inc.	DQ Managed Stores, Inc.
Edmonds Material and Equipment Co.	Borsheim Jewelry Company, Inc	DQ Wholly-Owned Stores, Inc.
Justin Industries, Inc.	Brooks Sports, Inc.	DQ Joint Venture Stores, Inc.
AEG Processing Center No. 35, Inc.	Total Quality Apparel Resources	PJR Management, Inc.
AEG Processing Center No. 58, Inc.	The Buffalo News, Inc.	All Bilt Uniforms
Applied Processing Center No. 60, Inc.	Business Wire, Inc.	Command Uniforms
American Employers Group, Inc.	Clayton Commercial Buildings, Inc.	Commonwealth Uniforms Inc.
Applied Group Insurance Holdings, Inc.	CMH Hodgenville, Inc.	Crowley Garment Mfg Co Inc.
Applied Investigations Inc.	CMH Manufacturing, Inc.	Crowley Shirt Mfg Co Inc.
Applied Logistics, Inc.	CMH Set and Finish, Inc.	The Eagle Company
Applied Premium Finance, Inc.	CMH Manufacturing West, Inc.	Farriors, Inc.
Applied Risk Services of New York, Inc.	AL/TEX Homes, Inc.	The Fechheimer Brothers Co.
Applied Risk Services, Inc.	BR Agency, Inc.	Fulton Manufacturing Company
AU Holding Company, Inc.	Giles Industries, Inc.	Great Plains Uniforms
Applied Underwriters, Inc.	Southern Energy Homes, Inc.	Griffey Uniforms
AU Captive Risk Assurance Co.	CMH Transport, Inc.	Harris Uniforms
BH, LLC	Cavalier Homes, Inc.	Martin Manufacturing Company
Berkshire Indemnity Group Inc.	Fontana Wood Products, Inc.	McCain Uniform Company Inc.
Combined Claims Services, Inc.	Fontana Wood Products of Oregon, Inc.	Metro Uniforms
Coverage Dynamics Group, Inc.	CMH Homes, Inc.	Nick Bloom Uniforms
Commercial General Indemnity, Inc.	CMH of KY, Inc.	Nationwide Uniforms
California Insurance Company	CMH Parks, Inc.	Roberts Men's Shop
Continental Indemnity Company	Chatwell, Inc.	Silver State Uniforms
Applied Underwriters Captive Risk Assurance Company, Inc.	Freedom Warehouse Corp.	Simon's Incorporated
Illinois Insurance Company	Vanderbilt ABS Corp.	Sol Frank Uniforms Inc.
North American Casualty Co.	Vanderbilt Mortgage and Finance, Inc.	Uniforms of Texas
Promesa Health, Inc.	Vanderbilt SPC, Inc.	Universal Uniforms
Pennsylvania Insurance Company	Vanderbilt Property&Casualty Insurance Co., Ltd.	Waynesburg Shirt Company Inc.
Strategic Staff Management, Inc.	Homefirst Agency, Inc.	Zuckerbergs Uniforms
The Ben Bridge Corporation	21st Communities, Inc.	Fruit of the Loom, Inc.
Ben Bridge Jeweler, Inc.	21st Mortgage Corporation	Union Underwear Co., Inc
Benjamin Moore & Co.	Henley Holdings, LLC	Cumberland Asset Management, Inc.

Complementary Coatings Corporation	21 SPC, Inc.	Fruit of the Loom Direct, Inc.
Eco Color Company	Clayton Homes, Inc.	Vanity Fair, Inc.
The Indecor Group, Inc.	CMH Capital, Inc.	VFI-Mexico, Inc.
Burlington Northern Santa Fe, LLC	CMH Services, Inc.	The BVD Licensing Corporation
FreightWise, Inc.	Clayton Education Corp.	Russell Athletic Corporation
Burlington Northern Santa Fe Insurance Company, Ltd.	Cort Business Services Corporation	Martin Mills, Inc.
BNSF Logistics International, Inc.	Central States of Omaha Companies, Inc.	Camp Manufacturing Company
Royal Cargo Lines	Central States Indemnity Co. of Omaha	Leesburg Yarn Mills, Inc.
Albacor Shipping (USA) Inc.	CSI Life Insurance Company	Rabun Apparel, Inc.
BNSF Railway Company	Roxell USA, Inc. (fka Agile Manufacturing Inc.)	FTL Sales Company, Inc.
Bayport Systems, Inc.	CTB Credit Corp	FTL Regional Sales Co., Inc.
Burlington Northern Santa Fe Manitoba, Inc.	CTB Inc.	Union Sales, Inc.
Fruit of the Loom Trading Company	Berkshire Hathaway Homestate Insurance Company	Anderson Retail, Inc.
Fruit of the Loom, Inc. (Sub)	Continental Divide Insurance Company	Penn Coal Land, Inc.
Mobile Disaster Structures, Inc	Cypress Insurance Company	Penn Pocahontas Coal Co.
Forest River Financial Services, Inc.	Oak River Insurance Company	TRH Holding Corp.
Forest River Housing, Inc.	Redwood Fire and Casualty Insurance Company	Alexander-Otto Company, LLC
Forest River, Inc.	Boot Royalty Company	Precision Millwork Settings LLC
Forest River Manufacturing LLC	Chippewa Shoe Company	Marmon Holdings, Inc.
Mapletree Transportation, Inc.	Footwear Investment Company	Getz Bros. & Co. Zug, Inc.
Priority One Financial Services, Inc.	H.J. Justin & Sons, Inc.	Webb Wheel Products, Inc.
Veritas Insurance Group, Inc.	Justin Belt Company, Inc.	Perfection Hy-Test Company
FlightSafety Capital Corp.	Justin Brands, Inc.	Marathon Suspension Systems, Inc.
FlightSafety Development Corp.	Justin Boot Company	Fontaine Trailer Company
FlightSafety International Inc.	J.S Justin, Inc.	Fontaine Modification Company
FlightSafety New York, Inc.	Nocona Boot Company	Fontaine Fifth Wheel Company
FlightSafety Properties, Inc.	Tony Lama Company	Fontaine Commercial Trailer, Inc.
FlightSafety Services Corporation	Johns Manville Corporation	Fontaine Engineered Products, Inc.
Garan Central America Corp.	Johns Manville, Inc.	Marmon-Herrington Company
Garan Incorporated	Seventeenth Street Realty, Inc.	Triangle Suspension Systems, Inc.
Garan Manufacturing Corp.	Johns Manville China, Ltd.	Fontaine Spray Suppression Company
Garan Services Corp	Jordan's Furniture, Inc.	TSE Brakes, Inc.
Criterion Insurance Agency	Kansas Bankers Surety Company	Union Tank Car Company
GEICO Corporation	Albecca, Inc.	Uni-Form Components Co.
Government Employees Financial Corp.	Active Organics, Inc.	Marmon Distribution Services, Inc.
GEICO Insurance Agency	Lubrizol Inter-Americas Corporation	Railserve, Inc.
GEICO Products, Inc.	Lubrizol Advanced Materials China, Inc.	Tiger-Sunbelt Industries, Inc.
International Insurance Underwriters, Inc.	The Lubrizol Corporation	Worldwide Containers, Inc.
Maryland Ventures, Inc..	Chemtool Incorporated	Exsif Worldwide, Inc.
Plaza Financial Services Co.	Lubrizol Advanced Materials FCC, Inc.	McLane Southern, Inc.
Plaza Resources Co.	Lubrizol Advanced Materials Holding Corporation	McLane Western, Inc.
Top Five Club, Inc.	LZ Holding Corporation	McLane Beverage Distribution, Inc.
GEICO Advantage Insurance Company	Lubrizol Advanced Materials International, Inc.	McLane Beverage Holding, Inc.
GEICO Casualty Co.	Lipotec Group Corp.	McLane Minnesota, Inc.
GEICO Choice Insurance Company	Lubrizol Enterprises, Inc.	McLane Express, Inc.
GEICO General Insurance Co.	Lubrizol International Management Corporation	JDS Properties, Inc.
Government Employees Insurance Co.	Lubrizol Overseas Trading Corporation	Intrepid JSB, Inc.
GEICO Indemnity Co.	MPP Pipeline Corporation	International Traders, Inc.
GEICO Secure Insurance Company	Noveon Hilton Davis, Inc.	First American Carriers, Inc.
General Re Corporation	Lubrizol Advanced Materials, Inc.	Meadowbrook Meat Company, Inc.
Gen Re Long Ridge LLC	Lubrizol Advanced Materials Gibraltar, Inc.	McLane New Jersey, Inc.
Elm Street Corporation	Lubricant Investments, Inc.	Kahn Ventures, Inc.
GRD Holdings Corporation	Marmon Water, Inc.	Empire Distributors, Inc.
Gen Re Intermediaries Corporation	Marmon Crane Services, Inc.	Empire Distributors of North Carolina, Inc.
General Re New England Asset Management	Marmon Electrical & Plumbing Products Distribution, Inc.	Horizon Wine & Spirits - Nashville, Inc.
Genesis Management and Insurance Services Corporation	Marmon Engineered Industrial & Metal Components, Inc.	Horizon Wine & Spirits - Chattanooga, Inc.
General Star Management Company	Marmon Retail & End User Technologies, Inc.	Delta Wholesale Liquors, Inc.
United States Aviation Underwriters, Incorporated	Marmon Wire & Cable, Inc.	Salado Sales, Inc.
General Re Financial Products Corporation	Lockwood Street Urban Renewal Corporation	McLane Foodservice, Inc.
General Reinsurance Corporation	Ecodyne Corporation	McCarty-Hull Cigar Company, Inc.
Faraday Capital Limited	J.L. Mining Company	Professional Datasolutions, Inc.
Genesis Insurance Company	Fontaine Truck Equipment Company	Claims Services, Inc.

General Star Indemnity Company	Marmon Retail Home Improvement Products, Inc.	Transco, Inc.
General Star National Insurance Company	Cerro Plumbing Retail, Inc.	McLane Company, Inc.
Helzberg's Diamond Shops, Inc.	Cerro Wire Distribution, Inc.	McLane Eastern, Inc.
HDS Redevelopment Corporation	Morgantown-National Supply, Inc.	McLane Midwest, Inc.
H. H. Brown Shoe Company, Inc.	Procrane Holdings, Inc.	McLane Suneast, Inc.
Running with Heels, Inc.	RCP Investment, Inc.	McLane Mid-Atlantic, Inc.
BH Shoe Holdings, Inc.	Wells Lamont Retail, Inc.	C & R Insurance Services, Inc.
Vision Retailing, Inc.	HG-Power Plant. Inc.	C & R Legal Insurance Agency, LLC
American All Risk Insurance Services Inc.	Marmon Natural Resource & Transportation Service	Medical Protective Finance Corporation
American Commercial Claims Administrators Inc	UTLX Company	The Medical Protective Company
Brookwood Insurance Company	Amarillo Gear, Inc.	Medical Protective Insurance Services, Inc.
Princeton Advertising & Marketing Group, Inc.	WestGUARD Insurance Company	Hallmark Sweet, Inc.
Alexander Road Insurance Agency, Inc.	Berkshire Hathaway Assurance Corporation	Stern/Leach Company
Princeton Insurance Company	EastGUARD Insurance Company	Rio Grande, Inc.
Medical Protective Corporation	Wesco-Financial Insurance Company	See's Candies, Inc
Princeton Risk Protection, Inc.	National Liability & Fire Insurance Company	Sees Candy Shops, Incorporated
MedPro Risk Retention Services, Inc.	National Indemnity Company of Mid-America	BHSF, Inc.
Somerset Services, Inc	National Fire & Marine Insurance Company	Ambucor Health Solutions, Inc.
Accurate Installations, Inc.	National Indemnity Company	ScottCare Corporation
Benson, Ltd.	Atlanta International Insurance Company	The Scott Fetzer Company
Benson Industries, Inc.	Stonewall Insurance Company	Campbell Hausfeld/Scott Fetzer Company
Cubic Designs, Inc.	Columbia Insurance Company	Adalet/Scott Fetzer Company
Hardy Frames, Inc.	NorGUARD Insurance Company	Western/Scott Fetzer Company
HeatPipe Technology, Inc.	Commercial Casualty Insurance Company	Halex/Scott Fetzer Company
Hohmann & Barnard, Inc.	Unione Italiana Reinsurance Company of America, Inc.	Stahl/Scott Fetzer Company
MiTek Holdings, Inc.	Seaworthy Insurance Company	France/Scott Fetzer Company
MiTek Industries, Inc.	Finial Reinsurance Company	Wayne/Scott Fetzer Company
Kova Solutions, Inc.	National Indemnity Company of the South	Carefree/Scott Fetzer Company
Miller-Sage, Inc.	AmGUARD Insurance Company	Scott Fetzer Financial Group, Inc.
Rush Air Inc	BNJ NetJets, Inc.	UCFS Europe Company
SidePlate Systems, Inc.	Executive Jet Europe, Inc.	BH Finance, Inc.
SSS Acquisition Inc.	Executive Jet Management, Inc.	United Consumer Financial Services Company
TMI Climate Solutions, Inc.	NetJets Aviation, Inc.	United Direct Finance, Inc.
MiTek USA, Inc.	NetJets Europe Holdings, LLC	World Book, Inc.
United Steel Products Company	NetJets Inc.	World Book Encyclopedia, Inc.
121 Acquisition Co., LLC	NetJets International, Inc.	World Book/Scott Fetzer Company
Floors, Inc.	NetJets Large Aircraft, Inc.	SHX Leasing, Inc.
NFM of Kansas, Inc.	NetJets Sales, Inc.	SHX Flooring, Inc.
LMG Ventures, LLC	NetJets Services, Inc.	Shaw International Services, Inc.
Nebraska Furniture Mart, Inc.	NetJets U.S., Inc.	Pro Installations, Inc.
NFM SERVICES, LLC	NJE Holdings, LLC	Shaw Contract Flooring Installation Services, Inc.
Homemakers Plaza, Inc.	NJI Sales, Inc.	Shaw Contract Flooring Services, Inc.
TXFM, Inc.	Marquis Jet Partners, Inc.	Spectra Contract Flooring Puerto Rico, Inc.
WMC Corp.	Marquis Jet Holdings, Inc.	Shaw Industries Group, Inc.
First Berkshire Hathaway Life Insurance Company	Brainy Toys, Inc.	Shaw Industries, Inc.
Berkshire Hathaway Life Insurance Company of Nebraska	OTC Brands, Inc.	Shaw Diversified Services, Inc.
BHG Life Insurance Company	OTC Direct, Inc.	Shaw Transport, Inc.
Ringwalt & Liesche Co.	Fun Express LLC	Queen Carpet Corporation
Brilliant National Services, Inc.	Mindware Corporation	Shaw Floors, Inc.
Soco West, Inc.	M W Wholesale, Inc.	Shaw Retail Properties, Inc.
Whittaker, Clark & Daniels, Inc.	Oriental Trading Company, Inc.	Shaw Funding Company
L.A. Terminals, Inc.	OTC Worldwide Holdings, Inc.	Star Furniture Company
Boat America Corporation	Ace Mailing Services, Inc.	CJE II
Boat/U.S, Inc.	BH Media Group, Inc.	Mouser Electronics, Inc.
Vessel Assist Association of America, Inc.	BH Media Group Holdings, Inc.	Ray-Q, Inc
BHG Structured Settlements, Inc.	Diversified Mailing, Inc.	Sager Electrical Supply Co. Inc
Resolute Management Inc.	LEE Distributing Services, Inc.	TTI, Inc.
International America Group Inc.	Midlands Newspapers, Inc.	Gateway Underwriters Agency, Inc.
International American Management Company	Mail Tech, LTD.	U.S. Investment Corporation
Northern States Agency, Inc.	Omaha World-Herald Company	United States Liability Insurance Company
Finial Holdings, Inc.	World Investments, Inc.	Mount Vernon Fire Insurance Company
CLAL U.S. Holdings, Inc.	World Marketing, Inc.	Mount Vernon Specialty Insurance Company

GUARD Financial Group, Inc.	World Publishing Enterprises, Inc.	U.S. Underwriters Insurance Co.
GUARD Insurance Group, Inc.	World Technologies, Inc.	Blue Chip Stamps, Inc.
GUARDco, Inc.	TPC European Holdings, LTD.	Montana Retail Properties, Inc.
Affiliated Agency Operations Co.	TPC North America, Ltd.	MS Property Company
InterGUARD, Ltd.	TPC N.A.S.A., LLC	AJF Warehouse Distributors, Inc.
TransGUARD, Ltd.	The Pampered Chef, Ltd.	XTRA Finance Corporation
Hawthorn Life International Limited	Precision Steel Warehouse - Charlotte S/C	XTRA Intermodal, Inc.
Consolidated Health Plans Inc.	Precision Steel Warehouse, Inc.	RENTCO Trailer Corporation
Affordable Housing Partners, Inc.	Precision Brand Products, Inc.	X-L-Co., Inc.
Boat Owners Association of the United States	R.C. Willey Home Furnishings	XTRA Corporation
American Centennial Insurance Company	Richline Group, Inc	XTRA Companies, Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL TAXES					
2	Federal Income Taxes	1				
3						
4	FICA					
5	1991-1992	16,493				
6	2012	-98,968			-98,968	
7	2013			7,899,899	7,913,552	
8						
9	FUTA					
10	2012	449			449	
11	2013			102,339	101,337	
12						
13	Payroll Tax - Performance					
14	2013	576,937		-576,937		
15	subtotal Federal	494,912		7,425,301	7,916,370	
16						
17	STATE OF NEVADA					
18	AD VALOREM					
19	2012-2013		382,697	8,889,015	8,506,318	
20	2013-2014			9,284,844	8,991,443	
21						
22	COUNTY FRANCHISE					
23	2012	228,713		50,544	279,257	
24	2013			284,489	5,226	
25						
26	UNEMPLOYMENT					
27	2012	2,151			2,151	
28	2013			180,811	178,245	
29						
30	BUSINESS TAX					
31	2012	235,143		668	235,811	
32	2013			1,344,214	926,660	
33						
34	PUCN MILL ASSESSMENT					
35	2012/2013	596,644		2,694,069	1,943,678	
36						
37	Sales tax on P Card			59,576	59,576	
38	Subtotal Nevada	1,062,651	382,697	22,788,230	21,128,365	
39						
40						
41	TOTAL	2,326,748	382,697	31,287,438	30,354,422	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	STATE OF CALIFORNIA					
2	AD VALOREM					
3	Pre 2013	434,059		-47	434,012	
4	2013			915,625	458,286	
5						
6	UNEMPLOYMENT					
7	Pre 2013	-572		624	52	
8	2013					
9						
10	CORPORATION			8,800		
11						
12	Subtotal California	433,487		925,002	892,350	
13						
14	PAUITE INDIAN TRIBE					
15	POSSESSORY INTEREST					
16	2013			417,337	417,337	
17						
18	Subtotal Paiute Indian Tribe			417,337	417,337	
19						
20	STATE OF UTAH					
21	2013 INCOME TAX					
22						
23	STATE OF OREGON					
24	2013 INCOME TAX					
25						
26	ACCRUED PAYROLL TAX					
27	NON PROD CLEARING	335,698		-268,432		
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	2,326,748	382,697	31,287,438	30,354,422	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
1		9,510,818			-9,510,818	2
						3
						4
16,493						5
						6
-13,653		3,979,140			3,920,759	7
						8
						9
						10
1,002		26,249			76,090	11
						12
						13
					-576,937	14
3,843		13,516,207			-6,090,906	15
						16
						17
						18
		7,400,849			1,488,166	19
548,068	254,667	7,831,541			1,453,303	20
						21
						22
		50,544				23
279,263		284,027			462	24
						25
						26
						27
2,566		95,972			84,839	28
						29
						30
		563			105	31
417,554		1,127,796			216,418	32
						33
						34
1,347,035					2,694,069	35
						36
		59,576				37
2,594,486	254,667	16,850,868			5,937,362	38
						39
						40
3,131,734	254,667	31,588,572			-301,134	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
		-47				3
457,339		915,625				4
						5
						6
					624	7
						8
						9
8,800		-111,418			120,218	10
						11
466,139		804,160			120,842	12
						13
						14
						15
		417,337				16
						17
		417,337				18
						19
						20
						21
						22
						23
						24
						25
						26
67,266					-268,432	27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
3,131,734	254,667	31,588,572			-301,134	41

Schedule Page: 262 Line No.: 2 Column: l

	GAS	OTHER	TOTAL
FEDERAL			
Income Tax	$ (11,722,134)	$ 2,211,316	$ (9,510,818)
FICA	568,331	3,352,428	3,920,759
FUTA	3,749	72,341	76,090
Payroll tax - Performance Pay	-	(576,937)	(576,937)
TOTAL FEDERAL	(11,150,054)	5,059,149	(6,090,906)
STATE OF NEVADA			
Property Tax			
2012-2013	962,566	525,600	1,488,166
2013-2014	964,526	488,777	1,453,302
	1,927,092	1,014,377	2,941,468
County Franchise			
2012	-	-	-
2013	462	-	462
	462	-	462
Unemployment			
2012	-	-	-
2013	13,707	71,132	84,839
	13,707	71,132	84,839
Business Tax	216,523	-	216,523
PUCN Mill Assessment	-	2,694,069	2,694,069
TOTAL STATE OF NEVADA	2,157,784	3,779,577	5,937,362
STATE OF CALIFORNIA			
Ad Valorem	-	-	-
Unemployment	-	624	624
Corporate Franchise		120,218	120,218
TOTAL STATE OF CALIFORNIA	-	120,842	120,842
STATE OF UTAH			
Income Tax			-
ACCRUED PAYROLL TAX			
Non Prod Clearing		(268,432)	(268,432)
TOTAL	**$ (8,992,270)**	**$ 8,691,136**	**$ (301,134)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	3,270			411.4	2,394	
4	7%						
5	10%	7,940,526			411.4	1,284,172	
6							
7							
8	TOTAL	7,943,796				1,286,566	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12	4%	1,414			411.4	1,156	
13	10%	905,279			411.4	60,271	
14	Total Gas	906,693				61,427	
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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46							
47							
48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
876	44 Years		3
			4
6,656,354	44 Years		5
			6
			7
6,657,230			8
			9
			10
			11
258	63 Years		12
845,008	63 Years		13
845,266			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
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			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Tax Gross Up-Customer Advance,	16,071,033	107/186	6,136,856	5,679,049	15,613,226
2	CIAC and Trnch/Substrcr		252/456/495			
3						
4	General Contingency	650,000			35,910,223	36,560,223
5						
6	Other Tax Liabilities	790,181	190/282/409	7,047,777	6,257,596	
7						
8	OnLine Consolidation	14,243,338	107	29,160,762	14,917,424	
9						
10	Minor Items	101,314	various	76,904	111,469	135,879
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
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32						
33						
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35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	31,855,866		42,422,299	62,875,761	52,309,328

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

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

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							14
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							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	429,809,140	56,297,343	31,921,771
3	Gas	34,003,897	8,701,290	748,033
4				
5	TOTAL (Enter Total of lines 2 thru 4)	463,813,037	64,998,633	32,669,804
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	463,813,037	64,998,633	32,669,804
10	Classification of TOTAL			
11	Federal Income Tax	463,525,090	65,286,580	32,669,804
12	State Income Tax	287,947	-287,947	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
		182310	5,566,424	182310	8,919,279	457,537,567	2
		182310	437,642	182310	171,370	41,690,882	3
							4
			6,004,066		9,090,649	499,228,449	5
							6
							7
							8
			6,004,066		9,090,649	499,228,449	9
							10
			6,004,066		9,090,649	499,228,449	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Divestiture Costs	284,306		284,306
4	Bond Redemptions	10,594,327		864,364
5	FAS 109 Flowthroughs	40,798,738		
6	Deferred Energy	-11,686,800	15,800,050	184,668
7	Electric - Other (See Footnote	56,576,397	46,410,991	61,463,527
8				
9	TOTAL Electric (Total of lines 3 thru 8)	96,566,968	62,211,041	62,796,865
10	Gas			
11				
12	Bond Redemptions	-478,100		
13	FAS 109 Flowthrough	8,475,415		
14	Deferred Energy	-6,080,535	8,212,629	223,286
15	Gas - Other (See Footnote)	8,058,443	1,615,948	3,866,177
16				
17	TOTAL Gas (Total of lines 11 thru 16)	9,975,223	9,828,577	4,089,463
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	106,542,191	72,039,618	66,886,328
20	Classification of TOTAL			
21	Federal Income Tax	106,542,191	72,039,618	66,886,328
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
						9,729,963	4
		182310	1,298,634			39,500,104	5
						3,928,582	6
						41,523,861	7
							8
			1,298,634			94,682,510	9
							10
							11
						-478,100	12
		182310	254,260			8,221,155	13
						1,908,808	14
						5,808,214	15
							16
			254,260			15,460,077	17
							18
			1,552,894			110,142,587	19
							20
			1,552,894			110,142,587	21
							22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 7 Column: a

	Balance at Beginning of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Balance at End of Year
Detail of Electric - Other (Line 7)				
Caughlin Ranch Insurance Reserve	$ -	$ 8,155,000	$ -	$ 8,155,000
Deferred Conservation	9,307,523	3,808,359	25,284,217	(12,168,335)
Mark to Market	-	5,042,512	-	5,042,512
Pension Liability - Reg Asset (FAS158)	32,205,002	-	15,664,574	16,540,428
Regulatory Assets	15,063,869	29,405,120	20,514,733	23,954,256
Other	3	-	3	-
Total Electric - Other (Line 7)	$ 56,576,397	$ 46,410,991	$ 61,463,527	$ 41,523,861

Schedule Page: 276 Line No.: 15 Column: a

	Balance at Beginning of Year	Amounts Debited to Account 410.1	Amounts Credited to Account 411.1	Balance at End of Year
Detail of Gas - Other (Line 15)				
Deferred Conservation	$ 717,568	$ 498,828	$ 808,420	$ 407,976
Pension Liability - Reg Asset (FAS158)	7,001,190	-	2,361,402	4,639,788
Regulatory Assets	339,685	1,117,119	696,355	760,449
Other	-	1	-	1
Total Gas - Other (Line 15)	$ 8,058,443	$ 1,615,948	$ 3,866,177	$ 5,808,214

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Tax Unamortized ITC	4,765,767	190	725,958		4,039,809
2						
3	Regulatory Deferred Income Taxes	5,669,038	182	5,935,160	5,465,190	5,199,068
4						
5	Gain on Property Sales Dkt. 10-06001	2,221,853	421	2,221,853		
6	Amort pd 1/11-12/13					
7						
8	Risk Management		186	292,706	387,800	95,094
9						
10	Equity Component Carry Charge-Energy Efficiency,	576,569	419	315,823	21,911	282,657
11	Gas Valves Dkts 10-06001/11-12020/13-06002/3					
12	Various amort pds					
13						
14	Tracy Combined Cycle Dkt. 10-06001	4,411,509	407	144,246		4,267,263
15	Amort pd 1/2011-7/2043					
16						
17	Piñon Pine Over-collection Dkt. 13-06002	63,709			35,799	99,508
18	Amort pd 1/2014-12/2016					
19						
20	GOB Lease Savings Dkt. 13-06002/3				4,868,870	4,868,870
21	Amort pd 1/14-12/16					
22						
23	ASD Labor Reduction Dkt. 13-06002/3				5,987,417	5,987,417
24						
25	Energy Efficiency/Renewable Programs	5,378,992	182	88,714,663	120,041,868	36,706,197
26	DktS 13-03004/13-07021 various amort pds					
27						
28	Refundable Depreciation-Customer Advances	349,806	407	352,593		-2,787
29	Dkt 10-06001/2 Amort pd 1/11-12/13					
30						
31	Electric Deferred Energy	32,693,492	182/557	36,492,259	3,798,767	
32	Dkt. 12-03005 various amort pds					
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	56,130,735		135,195,261	140,607,622	61,543,096

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	265,668,888	252,368,125
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	288,102,833	280,384,352
5	Large (or Ind.) (See Instr. 4)	177,007,560	167,829,992
6	(444) Public Street and Highway Lighting	3,999,740	3,950,001
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	734,779,021	704,532,470
11	(447) Sales for Resale	50,367,908	44,138,009
12	TOTAL Sales of Electricity	785,146,929	748,670,479
13	(Less) (449.1) Provision for Rate Refunds	5,427,066	
14	TOTAL Revenues Net of Prov. for Refunds	779,719,863	748,670,479
15	Other Operating Revenues		
16	(450) Forfeited Discounts	685,396	753,497
17	(451) Miscellaneous Service Revenues	3,546,848	2,958,250
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	571,711	582,875
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	963,917	936,790
22	(456.1) Revenues from Transmission of Electricity of Others	17,398,932	16,044,910
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	23,166,804	21,276,322
27	TOTAL Electric Operating Revenues	802,886,667	769,946,801

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
2,369,782	2,284,198	281,282	279,230	2
				3
2,947,651	2,929,794	45,816	45,000	4
2,818,104	2,707,393	111	112	5
16,006	15,975	111	111	6
				7
				8
				9
8,151,543	7,937,360	327,320	324,453	10
1,034,029	1,122,367	20	27	11
9,185,572	9,059,727	327,340	324,480	12
				13
9,185,572	9,059,727	327,340	324,480	14

Line 12, column (b) includes $ 8,498,651 of unbilled revenues.

Line 12, column (d) includes 51,470 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 6 Column: b

Unmetered Sales:	Revenue:
444 Street Lights	$3,999,740

Schedule Page: 300 Line No.: 6 Column: c

Unmetered Sales:	Revenue:
444 Street Lights	$3,950,001

Schedule Page: 300 Line No.: 6 Column: d

Unmetered Sales:	MWH:
444 Street Lights	16,006

Schedule Page: 300 Line No.: 6 Column: e

Unmetered Sales:	MWH:
444 Street Lights	15,975

Schedule Page: 300 Line No.: 11 Column: c

This amount contains a reversal of a 2011 duplicate invoice from Truckee Donner PUD of $4,751.

Schedule Page: 300 Line No.: 17 Column: b

Description:	Amount
Misc. Service Revenue - Service Charges	$3,256,725
Remaining Other Revenue Under $250,000 Threshold	290,123
Total	$3,546,848

Schedule Page: 300 Line No.: 17 Column: c

Description:	Amount
Misc. Service Revenue - Service Charges	$2,841,120
Remaining Other Revenue Under $250,000 Threshold	117,130
Total	$2,958,250

Schedule Page: 300 Line No.: 21 Column: b

Other Electric Revenue - Amort CIAC and C/A Gross-Ups	$2,599,075
Other Electric Revenue - Amort Impact Fee	(2,075,002)
Remaining Other Revenue Under $250,000 Threshold	439,843
Total	$963,916

Schedule Page: 300 Line No.: 21 Column: c

Description:	Amount
Other Electric Revenue - Amort CIAC and C/A Gross-Ups	$2,596,560
Other Electric Revenue - Amort Impact Fee	(2,075,002)
Remaining Other Revenue Under $250,000 Threshold	415,232
Total	$936,790

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	None				
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Nevada					
2	D-1	1,946,399	210,870,480	210,252	9,257	0.1083
3	DM-1	384,968	38,818,601	69,121	5,569	0.1008
4	OD-1-TOU	3,900	413,497	471	8,280	0.1060
5	ODM-1-TOU	243	23,786	47	5,170	0.0979
6	OLS - R	1,911	285,757			0.1495
7	D-1-TOU-E	6,278	739,141	665	9,441	0.1177
8	D-1-CPP-DOM	6,594	754,277	714	9,235	0.1144
9	OD-1-TOU-HEV	127	12,762	12	10,583	0.1005
10	DEAA		10,341,361			
11	Unbilled	19,362	3,409,226			0.1761
12	Subtotal - Res Acct 440-0	2,369,782	265,668,888	281,282	8,425	0.1121
13	GS-1	619,649	68,200,301	40,086	15,458	0.1101
14	OGS-1-TOU	13,610	1,213,683	242	56,240	0.0892
15	SSR-2 (GS-1)	15	2,798	5	3,000	0.1865
16	GS-2	1,457,614	134,989,508	3,601	404,780	0.0926
17	GS-2-TOU	455,830	39,460,431	137	3,327,226	0.0866
18	SSR-3 (GS-2)	120	70,241	5	24,000	0.5853
19	OGS-2-TOU	169,437	14,613,742	377	449,435	0.0862
20	LSR-1 (GS-2-TOU)	1,644	285,185	4	411,000	0.1735
21	WP	7,980	749,913	1	7,980,000	0.0940
22	IS-1	15,011	1,027,675	312	48,112	0.0685
23	IS-2	188,351	11,878,073	1,045	180,240	0.0631
24	WCS-1 Wireless Com Level-1	83	7,549	1	83,000	0.0910
25	OLS - C	3,438	470,069			0.1367
26	GS-2 TOU (NG)					
27	DEAA		12,167,031			
28	Unbilled	14,869	2,966,634			0.1995
29	Subtotal - Sm Comm Acct. 442-4	2,947,651	288,102,833	45,816	64,337	0.0977
30	GS-3	1,182,242	94,886,286	89	13,283,618	0.0803
31	LSR LG (GS-3)	3,373	774,913	8	421,625	0.2297
32	GS-4 Large Transmission	441,047	27,746,813	5	88,209,400	0.0629
33	GS-3 (NG)	87,955	4,051,480	3	29,318,333	0.0461
34	GS-4 (NG)	1,086,248	38,356,714	3	362,082,667	0.0353
35	DO-GS-4 Large Transmission		1,869,875	3		
36	DEAA		7,198,688			
37	Unbilled	17,239	2,122,791			0.1231
38	Subtotal - Lg Comm Acct. 442.8	2,818,104	177,007,560	111	25,388,324	0.0628
39	S/L	16,006	3,930,714	111	144,198	0.2456
40	DEAA		69,026			
41	TOTAL Billed	8,100,073	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	726,280,369	0	0	0	0.0000
43	TOTAL	734,380,442	0	0	0	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Subtotal - Street Lighting Acct.	16,006	3,999,740	111	144,198	0.2499
2	Total Nevada	8,151,543	734,779,021	327,320	24,904	0.0901
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41	TOTAL Billed	8,100,073	0	0	0	0.0000
42	Total Unbilled Rev.(See Instr. 6)	726,280,369	0	0	0	0.0000
43	TOTAL	734,380,442	0	0	0	0.0000

FOOTNOTE DATA

Schedule Page: 304 Line No.: 10 Column: c

The DEAA revenue represents revenue billed pursuant to Sierra Pacific Power Company’s fuel adjustment clause.

Schedule Page: 304 Line No.: 27 Column: c

The DEAA revenue represents revenue billed pursuant to Sierra Pacific Power Company’s fuel adjustment clause.

Schedule Page: 304 Line No.: 36 Column: c

The DEAA revenue represents revenue billed pursuant to Sierra Pacific Power Company’s fuel adjustment clause.

Schedule Page: 304 Line No.: 40 Column: c

The DEAA revenue represents revenue billed pursuant to Sierra Pacific Power Company’s fuel adjustment clause.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Avista Energy Inc	SF	Vol. No. 7			
2	BC Power Exchange	OS	OATT			
3	Bonneville Power Administration	SF	Vol. No. 7			
4	Cargill	SF	Vol. No. 7			
5	Cargill	OS	OATT			
6	Citigroup Energy Inc.	AD	Vol. No. 7			
7	Fallon, City of	OS	Vol. No. 1			
8	Shell (Coral Power, LLC)	SF	Vol. No. 7			
9	Shell (Coral Power, LLC)	OS	Vol. No. 1			
10	Desert G&T	OS	OATT			
11	Exelon Generation Company	SF	Vol. No. 7			
12	Idaho Power Company	SF	Vol. No. 7			
13	Idaho Power Company	OS	NRSG			
14	Idaho Power Company	OS	OATT			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PPL Montana, LLC	SF	Vol. No. 7			
2	Los Angeles Dept. of Water and Power	SF	Vol. No. 7			
3	Morgan Stanley Capital Group	SF	Vol. No. 7			
4	Morgan Stanley Capital Group	OS	OATT			
5	Mt. Wheeler	SF	Vol. No. 1			
6	Nevada Power - Related PPA Solar One	AD	Vol. No. 7			
7	Nevada Power - Related PPA Solar One	SF	Vol. No. 7			
8	Northern California Power Agency	OS	OATT			
9	Noble Americas Gas and Power	SF	Vol. No. 1			
10	Noble Americas Gas and Power	OS	OATT			
11	Ormat - Orni 47 Wild Rose	OS	OATT			
12	PPL Energy Plus	SF	Vol. No. 1			
13	PPM Energy, LLC	OS	OATT			
14	Pacificorp	SF	Vol. No. 7			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Pacificorp	OS	NRSG			
2	Pacificorp	OS	OATT			
3	Pacific Gas & Electric Company	OS	OATT			
4	Pacificorp Power Marketing	SF	Vol. No. 7			
5	Plumas Sierra	OS	OATT			
6	Portland General	SF	Vol. No. 7			
7	Portland General	OS	OATT			
8	Powerex	SF	Vol. No. 7			
9	Powerex	OS	OATT			
10	Southern California Edison	SF	Vol. No. 7			
11	Southern California Edison	SF	Vol. No. 7			
12	Southern California Edison	OS	OATT			
13	Transalta Energy Marketing (US), Inc.	OS	OATT			
14	Transalta Energy Marketing (US), Inc.	SF	Vol. No. 7			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Truckee Donner PUD	OS	Vol. No. 1			
2	Pershing Hawthorne	RQ	Vol. No. 7			
3	Energy Imbalance Penalty Distribution	OS	Vol. No. 7			
4	Liberty Utilities - CalPeco	RQ	Vol. No. 7			
5	Liberty Utilities - CalPeco	RQ	Vol. No. 7			
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
200		700		700	1
30,457			63,574	63,574	2
5,925		255,825		255,825	3
10,815		456,024		456,024	4
4,742			7,476	7,476	5
			117	117	6
1,722			165,393	165,393	7
59,914		2,138,819		2,138,819	8
112,542			616,642	616,642	9
3			6	6	10
22		110		110	11
1,626		68,415		68,415	12
45			1,607	1,607	13
2,272			4,381	4,381	14
630,229	272,400	42,657,466	0	42,929,866	
403,800	0	5,737,381	1,700,661	7,438,042	
1,034,029	**272,400**	**48,394,847**	**1,700,661**	**50,367,908**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
455		12,458		12,458	1
100		1,300		1,300	2
37,791		1,379,279		1,379,279	3
23,237			42,871	42,871	4
6,592			508,763	508,763	5
			103	103	6
36,991		1,257,039		1,257,039	7
85			85	85	8
327		9,129		9,129	9
327			388	388	10
3,729			6,263	6,263	11
135		8,775		8,775	12
2,946			5,060	5,060	13
2,695		94,865		94,865	14
630,229	272,400	42,657,466	0	42,929,866	
403,800	0	5,737,381	1,700,661	7,438,042	
1,034,029	**272,400**	**48,394,847**	**1,700,661**	**50,367,908**	

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
60			1,683	1,683	1
36,510			71,981	71,981	2
1,430			2,781	2,781	3
204			9,826	9,826	4
4,148			72	72	5
825		32,650		32,650	6
1,721			2,694	2,694	7
185		3,250		3,250	8
1,909			4,033	4,033	9
			3,422	3,422	10
		5,000		5,000	11
3			7	7	12
8,322			13,991	13,991	13
527		13,743		13,743	14
630,229	272,400	42,657,466	0	42,929,866	
403,800	0	5,737,381	1,700,661	7,438,042	
1,034,029	**272,400**	**48,394,847**	**1,700,661**	**50,367,908**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,261			199,804	199,804	1
8,823		501,847		501,847	2
			-32,362	-32,362	3
621,406		42,155,619		42,155,619	4
	272,400			272,400	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
630,229	272,400	42,657,466	0	42,929,866	
403,800	0	5,737,381	1,700,661	7,438,042	
1,034,029	**272,400**	**48,394,847**	**1,700,661**	**50,367,908**	

Schedule Page: 310 Line No.: 2 Column: j
BC Power Exchange - Energy imbalance sales and losses.

Schedule Page: 310 Line No.: 5 Column: j
Cargill - Energy imbalance sales and losses.

Schedule Page: 310 Line No.: 6 Column: j
Citigroup Energy Group - Prior period adjustment.

Schedule Page: 310 Line No.: 7 Column: j
City of Fallon - Energy imbalance sales and losses.

Schedule Page: 310 Line No.: 9 Column: j
Shell (Coral Power, LLC) - Energy imbalance sales and losses.

Schedule Page: 310 Line No.: 10 Column: j
Desert G&T - Energy imbalance sales and losses.

Schedule Page: 310 Line No.: 13 Column: j
Idaho Power Company - NRSG sales.

Schedule Page: 310 Line No.: 14 Column: j
Idaho Power Company - Energy imbalance sales and losses.

Schedule Page: 310.1 Line No.: 4 Column: j
Morgan Stanley Capital Group, Inc. - Energy imbalance sales and losses

Schedule Page: 310.1 Line No.: 5 Column: j
Mt. Wheeler - Energy imbalance sales and losses.

Schedule Page: 310.1 Line No.: 6 Column: j
Nevada Power - Related PPA Solar One - Prior period adjustment.

Schedule Page: 310.1 Line No.: 8 Column: j
Northern California Power Agency - Energy imbalance sales and losses.

Schedule Page: 310.1 Line No.: 10 Column: j
Noble Americas Gas and Power - Energy imbalance sales and losses.

Schedule Page: 310.1 Line No.: 11 Column: j
Ormat - Orni 47 Wild Rose - Energy imbalance sales and losses.

Schedule Page: 310.1 Line No.: 13 Column: j
PPM Energy, LLC - Energy imbalance sales and losses.

Schedule Page: 310.1 Line No.: 14 Column: a
This footnote applies to all occurrences of "PacifiCorp" on pages 310-311. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 310.2 Line No.: 1 Column: j
Pacificorp - NRSG sales.

Schedule Page: 310.2 Line No.: 2 Column: j
Pacificorp - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 3 Column: j
Pacific Gas and Electric - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 4 Column: j
Pacificorp Power Marketing - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 5 Column: j
Plumas Sierra - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 7 Column: j
Portland General - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 9 Column: j
Powerex - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 10 Column: j
Souther California Edision - Prior period adjustment.

Schedule Page: 310.2 Line No.: 12 Column: j
Southern California Edison - Energy imbalance sales and losses.

Schedule Page: 310.2 Line No.: 13 Column: j
Transalta Energy Marketing (US), Inc. - Energy imbalance sales and losses.

Schedule Page: 310.3 Line No.: 1 Column: j

Truckee Donner PUD - Energy imbalance sales and losses.

Schedule Page: 310.3 Line No.: 3 Column: j

Energy imbalance penalty distribution.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,237,400	1,116,472
5	(501) Fuel	75,970,028	48,112,484
6	(502) Steam Expenses	2,134,471	1,725,347
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,400,180	1,287,493
10	(506) Miscellaneous Steam Power Expenses	9,991,285	7,554,122
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	90,733,364	59,795,918
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	278	16,457
16	(511) Maintenance of Structures	957,755	942,374
17	(512) Maintenance of Boiler Plant	4,076,167	5,500,780
18	(513) Maintenance of Electric Plant	1,655,398	2,237,849
19	(514) Maintenance of Miscellaneous Steam Plant	923,513	1,069,127
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	7,613,111	9,766,587
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	98,346,475	69,562,505
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		75
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		75
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		75

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,839,712	1,290,272
63	(547) Fuel	112,269,762	109,581,356
64	(548) Generation Expenses	983,274	956,459
65	(549) Miscellaneous Other Power Generation Expenses	3,709,833	3,935,044
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	118,802,581	115,763,131
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	8,244	25,728
70	(552) Maintenance of Structures	940,996	656,751
71	(553) Maintenance of Generating and Electric Plant	5,271,848	7,207,703
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	917,078	844,896
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	7,138,166	8,735,078
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	125,940,747	124,498,209
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	154,301,875	133,938,545
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	-306,787	14,301,075
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	153,995,088	148,239,620
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	378,282,310	342,300,409
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	264,959	171,876
84			
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,840,082	3,138,625
87	(561.3) Load Dispatch-Transmission Service and Scheduling	232,638	274,822
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	68,334	80,023
93	(562) Station Expenses	367,601	334,241
94	(563) Overhead Lines Expenses	1,785,760	1,986,951
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	412,840	780,097
97	(566) Miscellaneous Transmission Expenses	6,208,048	413,230
98	(567) Rents	936,047	966,587
99	TOTAL Operation (Enter Total of lines 83 thru 98)	13,116,309	8,146,452
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	45,677	52,775
102	(569) Maintenance of Structures	4,368	
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	460,402	500,454
108	(571) Maintenance of Overhead Lines	791,260	1,128,226
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,213	5,429
111	TOTAL Maintenance (Total of lines 101 thru 110)	1,302,920	1,686,884
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	14,419,229	9,833,336

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,672,368	2,841,192
135	(581) Load Dispatching	676,918	833,857
136	(582) Station Expenses	505,644	582,635
137	(583) Overhead Line Expenses	2,391,249	1,865,154
138	(584) Underground Line Expenses	942,983	615,512
139	(585) Street Lighting and Signal System Expenses	89,395	119,433
140	(586) Meter Expenses	1,320,362	1,241,786
141	(587) Customer Installations Expenses	57,941	46,080
142	(588) Miscellaneous Expenses	4,449,602	3,882,746
143	(589) Rents	983,675	978,057
144	TOTAL Operation (Enter Total of lines 134 thru 143)	14,090,137	13,006,452
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	350	327
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	1,739,061	1,345,739
149	(593) Maintenance of Overhead Lines	5,269,909	6,469,445
150	(594) Maintenance of Underground Lines	793,898	723,064
151	(595) Maintenance of Line Transformers		2,194
152	(596) Maintenance of Street Lighting and Signal Systems	485,177	449,075
153	(597) Maintenance of Meters	14,217	13,713
154	(598) Maintenance of Miscellaneous Distribution Plant	576,733	536,318
155	TOTAL Maintenance (Total of lines 146 thru 154)	8,879,345	9,539,875
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	22,969,482	22,546,327
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	719,186	813,619
160	(902) Meter Reading Expenses	1,799,311	2,242,870
161	(903) Customer Records and Collection Expenses	8,963,118	7,336,340
162	(904) Uncollectible Accounts	1,947,447	1,051,516
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	13,429,062	11,444,345

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	444,694	529,826
168	(908) Customer Assistance Expenses	18,176,950	26,303,314
169	(909) Informational and Instructional Expenses		1,020
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	18,621,644	26,834,160
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	562,486	578,581
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	562,486	578,581
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	18,709,933	21,337,669
182	(921) Office Supplies and Expenses	6,489,502	6,494,770
183	(Less) (922) Administrative Expenses Transferred-Credit	6,184,137	5,326,305
184	(923) Outside Services Employed	5,579,116	5,764,327
185	(924) Property Insurance	851,655	903,176
186	(925) Injuries and Damages	3,206,579	3,835,620
187	(926) Employee Pensions and Benefits	16,645,722	16,790,923
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	6,715,263	3,808,186
190	(929) (Less) Duplicate Charges-Cr.	760,904	789,280
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	4,388,110	3,886,271
193	(931) Rents	970,686	905,758
194	TOTAL Operation (Enter Total of lines 181 thru 193)	56,611,525	57,611,115
195	Maintenance		
196	(935) Maintenance of General Plant	3,286,853	3,647,665
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	59,898,378	61,258,780
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	508,182,591	474,795,938

Schedule Page: 320 Line No.: 76 Column: c

This amount contains a reversal of a duplicate 2011 invoice from Truckee Donner PUD of $55,132.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arizona Public Service Company	SF	N/A			
2	Argus Media	OS	N/A			
3	Avista Energy Inc.	AD	N/A			
4	Avista Energy Inc.	SF	N/A			
5	Avista Energy Inc.	OS	NRSG			
6	Barrick	EX	OATT			
7	Bonneville Power Administration	SF	N/A			
8	Bonneville Power Administration	OS	NRSG			
9	Burbank, City Of	SF	N/A			
10	Liberty Utilities - CalPeco	RQ	Contract			
11	Cargill	SF	N/A			
12	Chelan County PUD	OS	NRSG			
13	Citigroup Energy, Inc.	SF	N/A			
14	Fallon, City of	EX	OATT			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Coral Power, Inc. (Shell)	SF	N/A			
2	EDF Trading	SF	N/A			
3	Enserco - Black Hills Power	SF	N/A			
4	Grant County PUD	EX	OATT			
5	Idaho Power Company	SF	N/A			
6	Idaho Power Company	OS	NRSG			
7	PPL Montana, LLC	SF	N/A			
8	Los Angeles Department of Water & Powe	SF	N/A			
9	Macquarie Cook	SF	N/A			
10	Morgan Stanley Capital Group, Inc.	SF	N/A			
11	Mt. Wheeler	EX	OATT			
12	Newmont Mining	SF	N/A			
13	Newmont Mining	AD	N/A			
14	Northwest Energy	OS	NRSG			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	PPL Energyplus, LLC	SF	N/A			
2	Pacificorp	SF	N/A			
3	Pacificorp	OS	NRSG			
4	Iberdrola	SF	N/A			
5	Patua Power	SF	N/A			
6	Portland General Electric	SF	N/A			
7	Portland General Electric	OS	NRSG			
8	Powerex	SF	N/A			
9	Public Service Co. of New Mexico	SF	N/A			
10	Pugent Sound Energy	SF	N/A			
11	Pugent Sound Energy	OS	NRSG			
12	Raibow Energy Marketing	SF	N/A			
13	San Diego Gas and Electric	SF	N/A			
14	Seattle City Light	OS	NRSG			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Southern California Edison	SF	N/A			
2	Tacoma Power	OS	NRSG			
3	Transalta Energy Marketing (US), Inc	SF	N/A			
4	Truckee Donner PUD	EX	OATT			
5	Western Administration Upper	OS	NRSG			
6	AMOR II - US Geothermal	LU	LCSPP86			
7	AMOR II - US Geothermal	AD	LCSPP86			
8	Brady Power Partners	LU	LCSPP86			
9	Brady Power Partners	AD	LCSPP86			
10	Homestretch, LLC	LU	LCSPP86			
11	Homestretch, LLC	AD	LCSPP86			
12	Nevada Power - Related PPA Desert Peak	LU	Contract			
13	Nevada Power - Related PPA Blue Mounta	LU	Contract			
14	Nevada Power - Related PPA Blue Mounta	AD	Contract			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Nevada Power - Related PPA Jersey Vall	LU	Contract			
2	Nevada Power - Related PPA Jersey Vall	AD	Contract			
3	Nevada Power - Related PPA Lockwood	LU	Contract			
4	Nevada Power - Related PPA McGinness H	LU	Contract			
5	Frank Hooper Hydro	LU	LCSPP86			
6	Frank Hooper Hydro	AD	LCSPP86			
7	Nevada Power - Related PPA Galena 2	LU	Contract			
8	Galena 3 - Orni 14	LU	Contract			
9	Galena 3 - Orni 14	AD	Contract			
10	Kingston Hydro	LU	Contract			
11	Mill Creek Hydro	LU	Contract			
12	Beowawe Power, LLC	LU	Contract			
13	Burdette Geothermal	LU	Contract			
14	Nevada Solar One	LU	Contract			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	RO Hydro	LU	Contract			
2	Sparks, City of	LU	Contract			
3	Nevada Power - Related PPA Spring Vall	LU	Contract			
4	Nevada Power - Related PPA Spring Vall	AD	Contract			
5	Soda Lake Geothermal Power Company	LU	LCSPP86			
6	Steamboat 1 & 1A	LU	LCSPP86			
7	Steamboat II & III	LU	LCSPP86			
8	Steamboat II & III	AD	Contract			
9	Nevada Power - Related PPA Stillwater	LU	Contract			
10	Nevada Power - Related PPA Saltwells	LU	Contract			
11	Truckee-Carson Irrigation District	LU	LCSPP86			
12	Steamboat Hills LP	LU	LCSPP86			
13	Steamboat Hills LP	AD	Contract			
14	Nevada Power - Related PPA Tuscarora	LU	Contract			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Nevada Power - Related PPA Tuscarora	AD	Contract			
2	TMWA - Washoe Hydro Facility	LU	LCSPP86			
3	Landmark Power Brokers	SF	N/A			
4	International Continental Exchange	SF	N/A			
5	Western Energy Coordinating	SF	N/A			
6	Nevada Power REC Sales	OS	N/A			
7	Apple, INC REC Sales	OS	N/A			
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
200				10,750		10,750	1
					1,323	1,323	2
					-100	-100	3
39,350				1,145,200		1,145,200	4
53					1,628	1,628	5
13,115					355,175	355,175	6
450				26,750		26,750	7
173					1,677	1,677	8
1,024				117,771		117,771	9
					1,517,253	1,517,253	10
57,603				1,908,380		1,908,380	11
26					722	722	12
50				1,000		1,000	13
5,569					168,157	168,157	14
4,314,638				153,612,848	689,027	154,301,875	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

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

MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
20,025				589,246		589,246	1
3,431				143,785		143,785	2
428				32,804		32,804	3
23					631	631	4
43,384				938,527		938,527	5
80					2,393	2,393	6
8,410				292,612		292,612	7
48				2,592		2,592	8
68,134				2,183,171		2,183,171	9
13,350				776,492		776,492	10
19,034					538,384	538,384	11
1,432,149				34,200,403		34,200,403	12
-115					-2,588	-2,588	13
52					1,583	1,583	14
4,314,638				153,612,848	689,027	154,301,875	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,405				161,575		161,575	1
26,097				688,643		688,643	2
355					11,194	11,194	3
33,418				1,273,717		1,273,717	4
12,947				158,966		158,966	5
5,650				344,380		344,380	6
62					2,037	2,037	7
11,414				827,617		827,617	8
100				4,550		4,550	9
2,005				90,890		90,890	10
85					2,726	2,726	11
8,600				257,600		257,600	12
800				36,800		36,800	13
25					627	627	14
4,314,638				153,612,848	689,027	154,301,875	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
76				1,900		1,900	1
4					116	116	2
5,437				264,254		264,254	3
5,169					161,999	161,999	4
					37	37	5
76,624				6,794,754		6,794,754	6
					32,318	32,318	7
56,204				3,920,261		3,920,261	8
					-815	-815	9
10,479				1,447,020		1,447,020	10
67					5,127	5,127	11
83,358				2,006,377		2,006,377	12
231,774				5,527,567		5,527,567	13
-413					-15,846	-15,846	14
4,314,638				153,612,848	689,027	154,301,875	

Name of Respondent Sierra Pacific Power Company d/b/a NV Energy	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/21/2014	Year/Period of Report End of 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
75,568				2,280,472		2,280,472	1
-473					-18,753	-18,753	2
24,170				623,054		623,054	3
327,099				8,515,539		8,515,539	4
1,318				183,372		183,372	5
-6					-765	-765	6
55,872				982,080		982,080	7
150,690				8,663,681		8,663,681	8
					-1	-1	9
706				13,010		13,010	10
-2				840		840	11
110,315				6,248,482		6,248,482	12
150,839				7,945,114		7,945,114	13
36,991				6,961,591		6,961,591	14
4,314,638				153,612,848	689,027	154,301,875	

Name of Respondent Sierra Pacific Power Company d/b/a NV Energy	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/21/2014	Year/Period of Report End of 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
30				1,489		1,489	1
				31,381		31,381	2
250,549				4,042,437		4,042,437	3
-1					115	115	4
67,319				4,110,916		4,110,916	5
				-185,434		-185,434	6
164,249				11,051,323		11,051,323	7
4,329					302,033	302,033	8
198,473				5,552,443		5,552,443	9
123,753				3,022,065		3,022,065	10
6,459				494,463		494,463	11
74,302				9,779,594		9,779,594	12
469				52,860		52,860	13
147,200				3,803,291		3,803,291	14
4,314,638				153,612,848	689,027	154,301,875	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-407					4,333	4,333	1
47,039				3,232,324		3,232,324	2
				175		175	3
				21,194		21,194	4
				8,738		8,738	5
					-2,230,410	-2,230,410	6
					-153,283	-153,283	7
							8
							9
							10
							11
							12
							13
							14
4,314,638				153,612,848	689,027	154,301,875	

Schedule Page: 326 Line No.: 2 Column: l
Argus Media - Coal subscription service.

Schedule Page: 326 Line No.: 3 Column: l
Avista Energy - Prior period adjustment.

Schedule Page: 326 Line No.: 5 Column: l
Avista Energy, Inc. - NRSG purchases.

Schedule Page: 326 Line No.: 6 Column: l
Barrick - Energy imbalance purchases and losses.

Schedule Page: 326 Line No.: 8 Column: l
Bonneville Power Administration - NRSG purchases.

Schedule Page: 326 Line No.: 10 Column: l
Liberty Utilities - CalPeco - EBSA invoices.

Schedule Page: 326 Line No.: 12 Column: l
Chelan PUD - NRSG purchases.

Schedule Page: 326 Line No.: 14 Column: l
City Of Fallon - Energy imbalance purchases and losses.

Schedule Page: 326.1 Line No.: 4 Column: l
Grant County PUD - Energy imbalance purchases and losses.

Schedule Page: 326.1 Line No.: 6 Column: l
Idaho Power Company - NRSG purchases.

Schedule Page: 326.1 Line No.: 11 Column: l
Mt. Wheeler - Energy imbalance purchase and losses.

Schedule Page: 326.1 Line No.: 13 Column: l
Newmont Mining - Prior period adjustment.

Schedule Page: 326.1 Line No.: 14 Column: l
Northwest Energy - NRSG purchases.

Schedule Page: 326.2 Line No.: 2 Column: a
This footnote applies to all occurrences of "PacifiCorp" on pages 326-327. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 326.2 Line No.: 3 Column: l
Pacificorp - NRSG purchases.

Schedule Page: 326.2 Line No.: 7 Column: l
Portland General Electric - NRSG purchases.

Schedule Page: 326.2 Line No.: 11 Column: l
Pugent Sound Energy - NRSG purchases.

Schedule Page: 326.2 Line No.: 14 Column: l
Seattle City Light - NRSG purchases.

Schedule Page: 326.3 Line No.: 2 Column: l
Tacoma Power - NRSG purchases.

Schedule Page: 326.3 Line No.: 4 Column: l
Truckee Donner PUD - Energy imblance purchases and losses.

Schedule Page: 326.3 Line No.: 5 Column: l
Western Administration Upper - NRSG purchases.

Schedule Page: 326.3 Line No.: 7 Column: l
AMOR II - US Geothermal - Prior period adjustment.

Schedule Page: 326.3 Line No.: 9 Column: l
Brady Power Partners - Prior period adjustment.

Schedule Page: 326.3 Line No.: 11 Column: l
Homestretch, LLC - Prior Period Adjustment

Schedule Page: 326.3 Line No.: 14 Column: l
Nevada Power - Related PPA Blue Mountain - Prior period adjustment.

Schedule Page: 326.4 Line No.: 2 Column: l
Nevada Power - Related PPA Jersey Valley - Prior period adjustment.

Schedule Page: 326.4 Line No.: 6 Column: l

Frank Hooper Hydro - Prior period adjustment.

Schedule Page: 326.4 Line No.: 9 Column: l

Galena 3 - Orni 14 - Prior period adjustment.

Schedule Page: 326.5 Line No.: 4 Column: l

Nevada Power - Related PPA Spring Valley - Prior period adjustment.

Schedule Page: 326.5 Line No.: 8 Column: l

Steamboat II & III - Prior period adjustment.

Schedule Page: 326.6 Line No.: 1 Column: l

Nevada Power - Related PPA Tuscarora - Prior period adjustment.

Schedule Page: 326.6 Line No.: 6 Column: l

Nevada Power annual REC sales.

Schedule Page: 326.6 Line No.: 7 Column: l

Apple, Inc. REC sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	BC Power Exchange Corporation	Unknown	Unknown	NF
2	BC Power Exchange Corporation	Unknown	Unknown	NF
3	BC Power Exchange Corporation	BC Hydro Authority	Various	NF
4	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	NF
5	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	NF
6	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	OS
7	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	SFP
8	BC Power Exchange Corporation	Various	Various	NF
9	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	NF
10	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	OS
11	BC Power Exchange Corporation	BC Hydro Authority	Various	NF
12	BC Power Exchange Corporation	BC Hydro Authority	Various	OS
13	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	NF
14	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	OS
15	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	NF
16	BC Power Exchange Corporation	Various	California Independent System Ope	NF
17	BC Power Exchange Corporation	Various	Various	NF
18	BC Power Exchange Corporation	BC Hydro Authority	California Independent System Ope	SFP
19	BC Power Exchange Corporation	California Independent System Ope	BC Hydro Authority	NF
20	BC Power Exchange Corporation	Various	Various	NF
21	BC Power Exchange Corporation	Various	Various	AD
22	BC Power Exchange Corporation	Various	Various	AD
23	Cargill Power Markets LLC	Pacificorp	Barrick GS	NF
24	Cargill Power Markets LLC	Bonneville Power Administration	Pacificorp	NF
25	Cargill Power Markets LLC	Idaho Power Company	California Independent System Ope	NF
26	Cargill Power Markets LLC	Various	California Independent System Ope	NF
27	Cargill Power Markets LLC	Bonneville Power Administration	California Independent System Ope	NF
28	Cargill Power Markets LLC	Various	Various	AD
29	Cargill Power Markets LLC	Various	Various	AD
30	Coral Power LLC	Various	Various	NF
31	Coral Power LLC	Pacificorp	Barrick GS	SFP
32	Coral Power LLC	Various	Various	NF
33	Coral Power LLC	Various	Various	NF
34	Coral Power LLC	Various	Various	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Coral Power LLC	Various	Various	NF
2	Coral Power LLC	Various	Various	NF
3	Coral Power LLC	Various	Various	NF
4	Coral Power LLC	Newmont	California Independent System Ope	NF
5	Coral Power LLC	Various	Various	AD
6	Coral Power LLC	Various	Various	AD
7	Deseret Generation and Transmission	Pacificorp	Mt. Wheeler Power	AD
8	Deseret Generation and Transmission	Pacificorp	Mt. Wheeler Power	NF
9	Idaho Power Company Balancing Operations	Idaho Power Company-Valmy	Idaho Power Company	NF
10	Morgan Stanley Captial Group Inc.	Pacificorp	California Independent System Ope	NF
11	Morgan Stanley Captial Group Inc.	unknown	unknown	NF
12	Morgan Stanley Captial Group Inc.	Various	California Independent System Ope	NF
13	Morgan Stanley Captial Group Inc.	Public Service Company of New Mex	California Independent System Ope	NF
14	Morgan Stanley Captial Group Inc.	Various	California Independent System Ope	NF
15	Morgan Stanley Captial Group Inc.	Various	California Independent System Ope	NF
16	Morgan Stanley Captial Group Inc.	Various	Various	NF
17	Morgan Stanley Captial Group Inc.	Glacier Wind	California Independent System Ope	NF
18	Morgan Stanley Captial Group Inc.	Various	Various	NF
19	Morgan Stanley Captial Group Inc.	Various	California Independent System Ope	NF
20	Morgan Stanley Captial Group Inc.	Various	California Independent System Ope	SFP
21	Morgan Stanley Captial Group Inc.	Sierra Pacific Power	Deseret Generation Transmission &	NF
22	Morgan Stanley Captial Group Inc.	Sierra Pacific Power	California Independent System Ope	NF
23	Morgan Stanley Captial Group Inc.	California Independent System Ope	Various	NF
24	Morgan Stanley Captial Group Inc.	California Independent System Ope	Mt. Wheeler Power	NF
25	Morgan Stanley Captial Group Inc.	Various	Various	AD
26	Morgan Stanley Captial Group Inc.	Various	Various	AD
27	Mt. Wheeler TSA	unknown	unknown	LFP
28	Mt. Wheeler TSA	unknown	unknown	LFP
29	Myotis Power Marketing LLC	unknown	unknown	LFP
30	Noble Americas Gas & Power	Sierra Pacific Power	California Independent System Ope	NF
31	Northern California Power Agency	Various	Northern California Power Agency	AD
32	Northern California Power Agency	Northern California Power Agency	Northern California Power Agency	NF
33	ORNI 47	ORNI47 Wildrose	Los Angeles Dept of Water & Power	NF
34	ORNI 47	ORNI47 Wildrose	Los Angeles Dept of Water & Power	SFP
	TOTAL			

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

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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Pacific Gas & Electric Company-Utility	California Independent System Ope	California Independent System Ope	NF
2	Pacific Gas & Electric Company-Utility	California Independent System Ope	California Independent System Ope	NF
3	Pacific Gas & Electric Company-Utility	Various	Pacific Gas & Electric Company-Ut	AD
4	Pacific Gas & Electric Company-Utility	Various	Pacific Gas & Electric Company-Ut	AD
5	Pacific Gas & Electric Company-Utility	Various	Pacific Gas & Electric Company-Ut	AD
6	Pacificorp	Pacificorp	Pacificorp West	NF
7	Pacificorp	Pacificorp West	Pacificorp	NF
8	Pacificorp	Various	Pacificorp Pavant Load	NF
9	Pacificorp	Pacificorp West	Pacificorp	SFP
10	Pacificorp	Unknown	Unknown	NF
11	Pacificorp	Unknown	Unknown	NF
12	Pacificorp	Unknown	Unknown	SFP
13	Pacificorp	Various	Various	AD
14	Pacificorp	Various	Various	AD
15	Pacificorp	Various	Various	AD
16	Patua Project LLC	Sierra Pacific Power	Patua Project LLC	LFP
17	Patua Project LLC	Patua	Various	SFP
18	Plumas Sierra Rural ElectricCo-op	California Independent System Ope	Plumas Sierra Rural ElectricCo-op	LFP
19	Plumas Sierra Rural ElectricCo-op	Utah Area Municipal Power	Northern California Power Agency	SFP
20	Plumas Sierra Rural ElectricCo-op	Northern California Power Agency	Northern California Power Agency	NF
21	Plumas Sierra Rural ElectricCo-op	Various	Various	AD
22	Plumas Sierra Rural ElectricCo-op	Various	Various	AD
23	Portland General Electric	California Indepenent System Oper	Seattle City Light	NF
24	Portland General Electric	Portland General Electric	California Indepenent System Oper	NF
25	Portland General Electric	Portland General Electric	California Indepenent System Oper	NF
26	Portland General Electric	Portland General Electric	California Indepenent System Oper	NF
27	Portland General Electric	California Indepenent System Oper	Portland General Electric	NF
28	Portland General Electric	Various	Various	AD
29	Portland General Electric	Various	Various	AD
30	PPM Energy Inc	Pacificorp	California Indepenent System Oper	NF
31	PPM Energy Inc	Unknown	Unknown	NF
32	PPM Energy Inc	Bonneville Power Administration	Various	NF
33	PPM Energy Inc	Bonneville Power Administration	PPM Energy Inc	NF
34	PPM Energy Inc	Various	California Indepenent System Oper	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PPM Energy Inc	Various	Various	NF
2	PPM Energy Inc	Bonneville Power Administration	California Indepenent System Oper	NF
3	PPM Energy Inc	Bonneville Power Administration	California Indepenent System Oper	NF
4	PPM Energy Inc	California Indepenent System Oper	Grant County Power District	NF
5	PPM Energy Inc	Various	Various	AD
6	PPM Energy Inc	Various	Various	AD
7	PPM Energy Inc	Various	Various	AD
8	Ram Power TSA	unknown	unknown	LFP
9	Southern California Edison	California Independent System Ope	California Independent System Ope	NF
10	Transalta Energy Marketing (U.S.), Inc.	Pacificorp	California Independent System Ope	NF
11	Transalta Energy Marketing (U.S.), Inc.	Grant County Power District	California Independent System Ope	NF
12	Transalta Energy Marketing (U.S.), Inc.	Grant County Power District	California Independent System Ope	NF
13	Transalta Energy Marketing (U.S.), Inc.	Various	California Independent System Ope	NF
14	Transalta Energy Marketing (U.S.), Inc.	Grant County Power District	Various	NF
15	Transalta Energy Marketing (U.S.), Inc.	Various	Various	NF
16	Transalta Energy Marketing (U.S.), Inc.	Sierra Pacific Power	Various	NF
17	Transalta Energy Marketing (U.S.), Inc.	Various	Various	NF
18	Transalta Energy Marketing (U.S.), Inc.	California Independent System Ope	Various	NF
19	Transalta Energy Marketing (U.S.), Inc.	Various	Various	AD
20	Transalta Energy Marketing (U.S.), Inc.	Various	Various	AD
21	Barrick GoldStrike	Shell Energy North America	Barrick GoldStrike	FNO
22	City Of Fallon	Utah Associated Municipal Power S	City Of Fallon	FNO
23	Truckee Donner PUD	Northern California Power Agency	Truckee Donner PUD	FNO
24	Mt. Wheeler Power NITS	Deseret Generation and Transmissi	Mt. Wheeler Power	FNO
25	Bonneville - Harney	Bonneville Power Admin	Harney Electric	OLF
26	Bonneville - WREC	Bonneville Power Admin	Wells Rural Electric	OLF
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
V1-1,2,8	GON.IPP	SILVERPEAK55		16	16	1
V1-1,2,8	GON.IPP	SUMMIT120		335	335	2
V1-1,2,8	GON.PAV	M345		197	197	3
V1-1,2,8	GON.PAV	SILVERPEAK55		119	119	4
V1-1,2,8	GON.PAV	SUMMIT120		58	58	5
V1-1,2,8	HILLTOP345	GON.PAV		203	203	6
V1-1,2,8	HILLTOP345	GON.PAV		19,680	19,680	7
V1-1,2,8	HILLTOP345	GON.PAV		6,091	6,091	8
V1-1,2,8	HILLTOP345	M345		60	60	9
V1	HILLTOP345	M345		28	28	10
V1-1,2,8	HILLTOP345	SUMMIT120		11,206	11,206	11
V1	HILLTOP345	SUMMIT120		31	31	12
V1-1,2,8	M345	GON.IPP		5,495	5,495	13
V1	M345	GON.PAV		416	416	14
V1-1,2,8	M345	HILLTOP345		74	74	15
V1-1,2,8	M345	SILVERPEAK55		987	987	16
V1-1,2,8	M345	SUMMIT120		16,380	16,380	17
V1-1,2,8	M345	SUMMIT120		4,320	4,320	18
V1-1,2,8	SUMMIT120	HILLTOP345		89	89	19
V1-1,2,8	SUMMIT120	M345		917	917	20
V1						21
V1						22
V1-1,2,8	GON.PAV	BARRICK GS		8	8	23
V1-1,2,8	M345	GON.PAV		18	18	24
V1-1,2,8	M345	SILVERPEAK55		177	177	25
V1-1,2,8	M345	SUMMIT120		6,009	6,009	26
V1-1,2,8	SILVERPEAK55	M345		25	25	27
V1						28
V1						29
V1-1,2,8	GON.PAV	SPPC		6,510	6,510	30
V1-1,2,8	GON.PAV	BARRICK GS		720	720	31
V1-1,2,8	HILLTOP345	SPPC		511	511	32
V1-1,2,8	M345	SPPC		96,884	96,884	33
V1-1,2,8	M345	SPPC		2,088	2,088	34
			3,823	**3,242,505**	**3,216,698**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
V1-1,2,8	SPPC	GON.PAV		472	472	1
V1-1,2,8	SPPC	HILLTOP345		146	146	2
V1-1,2,8	SPPC	M345		785	785	3
V1-1,2,8	NEWMONT	SUMMIT120		2,195	2,195	4
V1						5
V1						6
V1	GON.IPP	MT. WHEELER		-3,725	-3,725	7
V1-1,2,8	GON.IPP	MT. WHEELER		3	3	8
V1-1,2,8	VALMYIPC	GON.PAV		2,313	2,313	9
V1-1,2,8	GON.IPP	SILVERPEAK55		17	17	10
V1-1,2,8	GON.IPP	SPPC		3	3	11
V1-1,2,8	GON.IPP	SUMMIT120		756	756	12
V1-1,2,8	GON.PAV	SILVERPEAK55		15	15	13
V1-1,2,8	GON.PAV	SUMMIT120		611	611	14
V1-1,2,8	HILLTOP345	SUMMIT120		194	194	15
V1-1,2,8	M345	GON.PAV		397	397	16
V1-1,2,8	M345	SILVERPEAK55		75	75	17
V1-1,2,8	M345	MT. WHEELER		16	16	18
V1-1,2,8	M345	SUMMIT120		10,662	10,662	19
V1-1,2,8	M345	SUMMIT120		7,992	7,992	20
V1-1,2,8	SPPC	GON.PAV		172	172	21
V1-1,2,8	SPPC	SUMMIT120		730	730	22
V1-1,2,8	SUMMIT120	M345		153	153	23
V1-1,2,8	SUMMIT120	MT. WHEELER		25	25	24
V1						25
V1						26
V1-1,2,7	GON.IPP	MACHACHEK230		33	33	27
V1-1,2,7	GON.IPP	MACHACHEK230		42	42	28
V1-1,2,7	EAGLE120	HILLTOP345		30	30	29
V1-1,2,8	SPPC	SUMMIT120		327	327	30
V1						31
V1-1,2,8	SUMMIT120	MARBLE 60		111	111	32
V1-1,2,8	WILDROSE	GON.IPP		24	24	33
V1-1,2,8	WILDROSE	GON.IPP		32,950	32,950	34
			3,823	**3,242,505**	**3,216,698**	

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
V1-1,2,8	NP15	SUMMIT120		1,573	1,573	1
V1-1,2,8	SUMMIT120	NP15		116	116	2
V1						3
V1						4
V1						5
V1-1,2,8	GON.PAV	HILLTOP345		4,290	4,290	6
V1-1,2,8	HILLTOP345	GON.PAV		33,361	33,361	7
V1-1,2,8	M345	GON.PAV		1,005	1,005	8
V1-1,2,8	M345	GON.PAV		2,232	2,232	9
V1-1,2,8	SPPC	GON.PAV		40	40	10
V1-1,2,8	SPPC	HILLTOP345		120	120	11
V1-1,2,8	SPPC	HILLTOP345		360	360	12
V1						13
V1						14
V1						15
V1-1,2,7				600	600	16
V1-1,2,8	PATUA	HILLTOP345		132,480	132,480	17
V1-1,2,7	GON.IPP	MARBLE60		10,416	10,416	18
V1-1,2,8	GON.PAV	MARBLE60		2,229	2,229	19
V1-1,2,8	SUMMIT120	MARBLE60		30	30	20
V1						21
V1						22
V1-1,2,8	GON.PAV	M345		40	40	23
V1-1,2,8	HILLTOP345	GON.PAV		95	95	24
V1-1,2,8	HILLTOP345	SUMMIT120		616	616	25
V1-1,2,8	M345	SUMMIT120		1,399	1,399	26
V1-1,2,8	SUMMIT120	M345		78	78	27
V1						28
V1						29
V1-1,2,8	GON.PAV	SUMMIT120		50	50	30
V1-1,2,8	HILLTOP345	GON.IPP		50	50	31
V1-1,2,8	HILLTOP345	GON.PAV		93	93	32
V1-1,2,8	HILLTOP345	SUMMIT120		80	80	33
V1-1,2,8	M345	GON.IPP		100	100	34
			3,823	**3,242,505**	**3,216,698**	

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Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
V1-1,2,8	M345	GON.PAV		140	140	1
V1-1,2,8	M345	SILVERPEAK55		179	179	2
V1-1,2,8	M345	SUMMIT120		5,411	5,411	3
V1-1,2,8	SUMMIT120	M345		17	17	4
V1						5
V1						6
V1						7
V1-1,2,7	SPPC	SILVERPEAK55		17	17	8
V1-1,2,8	SUMMIT120	SILVERPEAK55		3	3	9
V1-1,2,8	GON.PAV	SUMMIT120		806	806	10
V1-1,2,8	HILLTOP345	GON.PAV		8	8	11
V1-1,2,8	HILLTOP345	SILVERPEAK55		25	25	12
V1-1,2,8	HILLTOP345	SUMMIT120		2,010	2,010	13
V1-1,2,8	M345	HILLTOP345		158	158	14
V1-1,2,8	M345	SUMMIT120		1,621	1,621	15
V1-1,2,8	SPPC	SUMMIT120		4,952	4,952	16
V1-1,2,8	SUMMIT120	GON.PAV		131	131	17
V1-1,2,8	SUMMIT120	M345		329	329	18
V1						19
V1						20
V1	M345	Barrick	577	1,232,533	1,225,532	21
V1	Gonder.Pav	Fallon	54	86,897	82,440	22
V1	Gon.IPP	Truckee Donner	89	147,926	146,354	23
V1	Gonder.Pav	Mt. Wheeler	88	568,728	557,082	24
RS 15	Hilltop345	SPPC	831	125,852	125,821	25
RS 27	Hilltop345	SPPC	2,184	636,133	635,033	26
						27
						28
						29
						30
						31
						32
						33
						34
			3,823	**3,242,505**	**3,216,698**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	109	15	124	1
	2,288	318	2,606	2
	1,597	151	1,748	3
	555	97	652	4
	410	34	444	5
				6
	98,570	12,737	111,307	7
	32,149	3,566	35,715	8
	308	22	330	9
				10
	55,013	5,082	60,095	11
				12
	26,527	2,367	28,894	13
				14
	505	35	540	15
	5,431	574	6,005	16
	101,700	9,789	111,489	17
	22,212	2,805	25,017	18
	687	80	767	19
	5,556	496	6,052	20
		-1,123	-1,123	21
	-4,748	1,474	-3,274	22
	31	3	34	23
	139	16	155	24
	724	70	794	25
	30,034	2,366	32,400	26
	171	12	183	27
		-39	-39	28
	2,305	537	2,842	29
	35,076	3,214	38,290	30
	3,276	282	3,558	31
	3,162	292	3,454	32
	583,944	52,443	636,387	33
	9,500	818	10,318	34
12,313,213	**2,584,359**	**2,501,360**	**17,398,932**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,320	309	2,629	1
	809	104	913	2
	3,691	476	4,167	3
	14,297	1,744	16,041	4
		-818	-818	5
		-1,625	-1,625	6
	-14,200	-1,736	-15,936	7
	20	1	21	8
	13,179	1,672	14,851	9
	116	8	124	10
	20	1	21	11
	4,579	571	5,150	12
	59	6	65	13
	2,580	275	2,855	14
	774	72	846	15
	3,339	192	3,531	16
	424	47	471	17
	62	6	68	18
	65,053	6,644	71,697	19
	34,336	3,057	37,393	20
	1,328	155	1,483	21
	5,597	652	6,249	22
	990	78	1,068	23
	171	24	195	24
		-171	-171	25
	-1,192	404	-788	26
	105,930		105,930	27
	134,820		134,820	28
	96,300		96,300	29
	2,276	273	2,549	30
		-1	-1	31
	459	42	501	32
	172	20	192	33
	144,521	19,876	164,397	34
12,313,213	**2,584,359**	**2,501,360**	**17,398,932**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	10,188	1,259	11,447	1
	622	43	665	2
		-1	-1	3
		-15	-15	4
	298	26	324	5
	24,444	2,307	26,751	6
	226,833	16,607	243,440	7
	7,064	905	7,969	8
	11,486	1,497	12,983	9
	156	34	190	10
	827	99	926	11
	1,853	242	2,095	12
		-213	-213	13
	-13,721	5,341	-8,380	14
		-670	-670	15
	170,400		170,400	16
	288,900	39,743	328,643	17
	39,760	3,759	43,519	18
	8,520	806	9,326	19
	154	11	165	20
	-22	8	-14	21
		-119	-119	22
	176	24	200	23
	853	45	898	24
	4,092	409	4,501	25
	8,058	656	8,714	26
	602	71	673	27
		-13	-13	28
	-341	114	-227	29
	195	19	214	30
	342	24	366	31
	363	34	397	32
	394	43	437	33
	668	69	737	34
12,313,213	**2,584,359**	**2,501,360**	**17,398,932**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,081	126	1,207	1
	1,382	161	1,543	2
	33,949	4,148	38,097	3
	131	15	146	4
		-6	-6	5
	-53	17	-36	6
	475		475	7
	54,570		54,570	8
	23	3	26	9
	4,258	491	4,749	10
	31	3	34	11
	170	17	187	12
	10,547	859	11,406	13
	616	58	674	14
	9,590	1,070	10,660	15
	28,931	2,102	31,033	16
	1,021	67	1,088	17
	1,871	141	2,012	18
		-57	-57	19
	2,541	-3,983	-1,442	20
5,286,497		1,608,559	6,895,056	21
499,373		178,374	677,747	22
799,880		116,535	916,415	23
1,219,753		388,605	1,608,358	24
1,001,449			1,001,449	25
3,506,261			3,506,261	26
				27
				28
				29
				30
				31
				32
				33
				34
12,313,213	**2,584,359**	**2,501,360**	**17,398,932**	

Schedule Page: 328 Line No.: 1 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 2 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 3 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 4 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 5 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 6 Column: m
Secondary Services Provided
Schedule Page: 328 Line No.: 7 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 8 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 9 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 10 Column: m
Secondary Services Provided
Schedule Page: 328 Line No.: 11 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 12 Column: m
Secondary Services Provided
Schedule Page: 328 Line No.: 13 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 14 Column: m
Secondary Services Provided
Schedule Page: 328 Line No.: 15 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 16 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 17 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 18 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 19 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 20 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 21 Column: m
Out of Period Adjustment Schedule 1 settlement
Schedule Page: 328 Line No.: 22 Column: m
Out of Period Adjustment
Schedule Page: 328 Line No.: 23 Column: b
This footnote applies to all occurrences of "PacifiCorp" on pages 328-330. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company.
Schedule Page: 328 Line No.: 23 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 24 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 25 Column: m
Ancillary Service provided
Schedule Page: 328 Line No.: 26 Column: m

Ancillary Service provided

Schedule Page: 328 Line No.: 27 Column: m

Ancillary Service provided

Schedule Page: 328 Line No.: 28 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328 Line No.: 29 Column: m

Out of Period Adjustment

Schedule Page: 328 Line No.: 30 Column: m

Ancillary Service provided

Schedule Page: 328 Line No.: 31 Column: m

Ancillary Service provided

Schedule Page: 328 Line No.: 32 Column: m

Ancillary Service provided

Schedule Page: 328 Line No.: 33 Column: m

Ancillary Service provided

Schedule Page: 328 Line No.: 34 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 1 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 2 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 3 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 4 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 5 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.1 Line No.: 6 Column: m

Out of Period Adjustment

Schedule Page: 328.1 Line No.: 7 Column: m

Out of Period Adjustment

Schedule Page: 328.1 Line No.: 8 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 9 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 10 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 11 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 12 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 13 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 14 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 15 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 16 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 17 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 18 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 19 Column: m

Ancillary Service provided

Schedule Page: 328.1 Line No.: 20 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 21 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 22 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 23 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 24 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 25 Column: m
Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.1 Line No.: 26 Column: m
Out of Period Adjustment

Schedule Page: 328.1 Line No.: 27 Column: l
Deferral of Long term point to point transmission service

Schedule Page: 328.1 Line No.: 28 Column: l
Deferral of Long term point to point transmission service

Schedule Page: 328.1 Line No.: 29 Column: l
Deferral of Long term point to point transmission service

Schedule Page: 328.1 Line No.: 30 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 31 Column: m
Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.1 Line No.: 32 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 33 Column: m
Ancillary Service provided

Schedule Page: 328.1 Line No.: 34 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 1 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 2 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 3 Column: m
Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.2 Line No.: 4 Column: m
Out of Period Adjustment

Schedule Page: 328.2 Line No.: 5 Column: m
Out of Period Adjustment

Schedule Page: 328.2 Line No.: 6 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 7 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 8 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 9 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 10 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 11 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 12 Column: m
Ancillary Service provided

Schedule Page: 328.2 Line No.: 13 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.2 Line No.: 14 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.2 Line No.: 15 Column: m

Out of Period Adjustment

Schedule Page: 328.2 Line No.: 16 Column: l

Deferral of Long term point to point transmission service

Schedule Page: 328.2 Line No.: 17 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 18 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 19 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 20 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 21 Column: m

Out of Period Adjustment

Schedule Page: 328.2 Line No.: 22 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.2 Line No.: 23 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 24 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 25 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 26 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 27 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 28 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.2 Line No.: 29 Column: m

Out of Period Adjustment

Schedule Page: 328.2 Line No.: 30 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 31 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 32 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 33 Column: m

Ancillary Service provided

Schedule Page: 328.2 Line No.: 34 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 1 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 2 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 3 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 4 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 5 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.3 Line No.: 6 Column: m

Out of Period Adjustment

Schedule Page: 328.3 Line No.: 7 Column: l

Out of Period Adjustment

Schedule Page: 328.3 Line No.: 8 Column: l

Deferral of Long term point to point transmission service

Schedule Page: 328.3 Line No.: 9 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 10 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 11 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 12 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 13 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 14 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 15 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 16 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 17 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 18 Column: m

Ancillary Service provided

Schedule Page: 328.3 Line No.: 19 Column: m

Out of Period Adjustment Schedule 1 settlement

Schedule Page: 328.3 Line No.: 20 Column: m

Out of Period Adjustment

Schedule Page: 328.3 Line No.: 21 Column: m

Barrick GoldStrike Transmission Contract Term date is 10/30/2050. Ancillary services provided.

Schedule Page: 328.3 Line No.: 22 Column: m

City of Fallon - Transmission contract termination date is 2025. City of Fallon - Ancillary services provided.

Schedule Page: 328.3 Line No.: 23 Column: m

Truckee Donner PUD - Transmission contract termination date is 2027. Truckee Donner PUD - Ancillary services provided.

Schedule Page: 328.3 Line No.: 24 Column: m

Mt. Wheeler Network Transmission Service contract began August 1, 2012

Schedule Page: 328.3 Line No.: 25 Column: a

Bonneville-Harney transmission contract termination date is 2024.

Schedule Page: 328.3 Line No.: 26 Column: a

Bonneville-Wells transmission contract termination 2018. Local Facility Charge per the General Transfer Agreement with BPA.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Energy	NF	1,315	1,315	5,770	3,980		9,750
2	Bonneville Power Admin	LFP	508	508	20,070	17,554	19,684	57,308
3	Idaho Power Company	NF	2,320	2,320	252,861	83,818	-149,079	187,600
4	Los Angeles Department	OS	1,193	1,193	17,787			17,787
5	Nevada Power	NF	5,686	5,686	1,889	48,090		49,979
6	Pacificorp	NF	2,412	2,412	87,899	28,757	-26,376	90,280
7	Wells Rural	OS			136			136
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		13,434	13,434	386,412	182,199	-155,771	412,840

Schedule Page: 332 Line No.: 2 Column: g

Bonneville Power Administration - Prior period adjustment and O&M charges.

Schedule Page: 332 Line No.: 3 Column: g

Idaho Power Company - Prior period adjusment.

Schedule Page: 332 Line No.: 6 Column: a

PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company.

Schedule Page: 332 Line No.: 6 Column: g

Pacificorp - Prior period adjustment and transmission rate refund.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	242,236
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	79,144
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	General Management Expense	3,715,044
7	Director's Fees	351,686
8		
9		
10		
11		
12		
13		
14		
15		
16		
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18		
19		
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46	TOTAL	4,388,110

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

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

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			1,370,907		1,370,907
2	Steam Production Plant	16,721,848				16,721,848
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,617,526				17,617,526
7	Transmission Plant	10,374,245				10,374,245
8	Distribution Plant	23,833,183				23,833,183
9	Regional Transmission and Market Operation					
10	General Plant	5,018,116				5,018,116
11	Common Plant-Electric	5,354,105		9,086,403		14,440,508
12	TOTAL	78,919,023		10,457,310		89,376,333

B. Basis for Amortization Charges

The company began amortizing it's limited term common plant in 1996 pursuant to a Nevada Public Service Commission order in Docket Number 85-532

The rate used in calculating the amortization charge is based on rates developed during depreciation studies. The calculation of the rate is based upon the straight line methodology. The rate is applied to the depreciable plant balance of the limited common plant in Section "C"

SPPCO started recognizing Asset Retirement Costs in 2005. These costs are being accumulated in a Regulatory Asset account pending approval from the PUCN. Costs for 2012 and 2013 were $14.7 and $16.6 million respectively.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Plant						
13	310	566			2.73	Square	20.10
14	311	83,070	125.00	-9.00	3.11	125-R2	12.80
15	312	254,689	60.00	-13.00	3.62	60-R2	12.60
16	314	91,592	70.00	-17.00	4.28	70-R2	11.40
17	315	48,216	60.00	-10.00	2.61	60-S1.5	11.90
18	316	11,226	50.00	-11.00	4.17	50-R1.5	10.90
19	317	7,434					
20	Subtotal	496,793					
21							
22	Other Production Plt						
23	341	40,362		-3.00	3.27	Square	28.70
24	342	113,944		-3.00	2.98	Square	31.20
25	343	20,191		-7.00	3.63	Square	15.00
26	344	306,875		-3.00	3.40	Square	27.00
27	345	65,593		-4.00	3.28	Square	22.00
28	346	34,663		-2.00	2.87	Square	32.50
29	347	762					
30	Subtotal	582,390					
31							
32	Tramsmission Plant						
33	350	48,118	70.00		1.40	70-R4	59.80
34	352	19,482	55.00	-5.00	2.00	55-R4	45.40
35	353	216,387	65.00	-5.00	1.28	65-R3	54.60
36	354	131,597	65.00	-5.00	1.50	65-R3	53.00
37	355	80,423	70.00	-40.00	1.91	70-R3	55.60
38	356	155,382	65.00	-25.00	1.75	65-R4	51.60
39	357	8,147	60.00		1.68	60-S4	54.20
40	358	12,555	50.00		1.94	50-S3	43.20
41	359	447	70.00		1.13	70-R4	32.20
42	Subtotal	672,538					
43							
44	Distribution Plant						
45	360	8,215	65.00		1.34	65-R4	53.90
46	361	3,373	55.00	-5.00	1.87	55-R3	43.00
47	362	187,194	55.00	-10.00	1.65	55-R4	42.40
48	364	157,584	65.00	-40.00	1.73	65-R1	54.10
49	365	138,129	55.00	-70.00	2.72	55-R3	38.00
50	366	77,970	65.00	-10.00	1.52	65-R4	48.10

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	367	311,041	65.00	-50.00	2.15	65-R4	54.80
13	368	190,818	50.00	-5.00	1.65	50-R0.5	42.50
14	369	122,070	60.00	-25.00	1.36	60-R2	51.80
15	370	37,271	30.00		2.99	30-R0.5	23.00
16	371	7,470	35.00	-20.00	1.01	35-R2	24.20
17	373	38,635	50.00	-50.00	3.03	50-R2	38.70
18	374	1,288					
19	Subtotal	1,281,058					
20							
21	General Plant						
22	303	22,220	8.00		12.50	8-SQ	2.90
23	389	187	65.00		1.80	65-R4	48.40
24	390	10,496	57.00	-5.00	7.78	57-R4	42.70
25	391.1	2,652	20.00		5.00	20-SQ	14.40
26	391.2	4,444	5.00		20.00	5-SQ	3.20
27	391.3	346					
28	392	5,074	14.00	8.00	4.40	14-L1	7.70
29	393	55	20.00		5.00	20-SQ	3.10
30	394	3,024	25.00		4.00	25-SQ	4.60
31	395	785	15.00		6.67	15-SQ	5.40
32	396	2,165	14.00	8.00	6.76	14-R1.5	7.90
33	397	62,352	15.00		6.67	15-SQ	10.10
34	398	53	20.00		5.00	20-SQ	19.50
35	399.1	-11					
36	Subtotal	113,842					
37	Total Plant	3,146,621					
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Schedule Page: 336 Line No.: 10 Column: b

Does not include transportation equipment depreciation expense. Transportation expense is booked to the fleet clearing account, 184030, and allocated between capital and operations and maintenance projects.

Schedule Page: 336 Line No.: 12 Column: b

Depreciable plant base (Column b) is based upon depreciable plant in service at December 31, 2013.

Schedule Page: 336 Line No.: 12 Column: c

Avg. Service life, Net Salvage, Depr. rates, Curve type, and Avg. remaining life (columns c through g) are based on the most recent depreciation study approved by the PUCN December 2010 in Docket #10-06003.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Mill Tax assessment pursuant to Chapter 704				
2	of the Nevada Revised Statutes	2,694,069		2,694,069	
3					
4					
5	Annual FERC Charges pursant to Title 180 Code				
6	of Federal Regulations Part 382	296,393		296,393	
7					
8	Federal Issues		1,283,294	1,283,294	
9					
10					
11	Public Utilities Commission of Nevada		3,338,334	3,338,334	
12					
13					
14	California Public Utilities Commission		26,749	26,749	
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	2,990,462	4,648,377	7,638,839	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Electric	928	2,359,032					1
Gas	928	335,037					2
							3
							4
Electric	928	296,393					5
							6
							7
Electric	928	1,247,067					8
Gas	928	36,227					9
							10
Electric	928	2,786,022					11
Gas	928	552,312					12
							13
Electric	928	26,749					14
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		7,638,839					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric RD&D performed internally	
2	(1) e. Unconventional Generation	Wind Energy Programs
3	(1) e. Unconventional Generation	Solar Energy Programs
4	(1) e. Unconventional Generation	Gas Solar Thermal Water Heater Energy Programs
5	(1) a.ii Hydroelectric	Waterpower Energy Programs
6		
7	B. Electric RD&D performed externally	Edison Electric Institute
8		
9	Total	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
1,436,206		182.3	1,436,206		2
5,520,154		182.3	5,520,154		3
215,514		182.3	215,514		4
126,331		182.3	126,331		5
					6
	242,236	930.2	242,236		7
					8
7,298,205	242,236		7,540,441		9
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	10,292,955		
4	Transmission	3,556,318		
5	Regional Market			
6	Distribution	5,356,006		
7	Customer Accounts	4,981,480		
8	Customer Service and Informational	1,134,483		
9	Sales	303,122		
10	Administrative and General	18,345,127		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	43,969,491		
12	Maintenance			
13	Production	2,527,406		
14	Transmission	489,636		
15	Regional Market			
16	Distribution	3,269,887		
17	Administrative and General	661,126		
18	TOTAL Maintenance (Total of lines 13 thru 17)	6,948,055		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,820,361		
21	Transmission (Enter Total of lines 4 and 14)	4,045,954		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	8,625,893		
24	Customer Accounts (Transcribe from line 7)	4,981,480		
25	Customer Service and Informational (Transcribe from line 8)	1,134,483		
26	Sales (Transcribe from line 9)	303,122		
27	Administrative and General (Enter Total of lines 10 and 17)	19,006,253		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	50,917,546	14,938,778	65,856,324
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)	27,739		
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission	2,192,868		
36	Distribution			
37	Customer Accounts	1,841,279		
38	Customer Service and Informational	156,202		
39	Sales			
40	Administrative and General	3,100,007		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	7,318,095		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	822,689		
49	Administrative and General	72,314		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	895,003		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,	27,739		
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)	2,192,868		
57	Distribution (Lines 36 and 48)	822,689		
58	Customer Accounts (Line 37)	1,841,279		
59	Customer Service and Informational (Line 38)	156,202		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	3,172,321		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	8,213,098	2,409,654	10,622,752
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	59,130,644	17,348,432	76,479,076
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	22,454,955	8,632,403	31,087,358
69	Gas Plant	2,469,561	949,378	3,418,939
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	24,924,516	9,581,781	34,506,297
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,174,264	344,519	1,518,783
74	Gas Plant	231,930	68,046	299,976
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,406,194	412,565	1,818,759
77	Other Accounts (Specify, provide details in footnote):			
78	Job Orders, Regulatory Asset and Non-Operating	12,518,273	3,672,756	16,191,029
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	12,518,273	3,672,756	16,191,029
96	TOTAL SALARIES AND WAGES	97,979,627	31,015,534	128,995,161

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Account No.	Property Group	Plant	Depreciation
303	Intangible Software	$117,066,337	$68,892,658
389	Land & Land Rights	9,708,090	157,225
390	Structures & Improvements	36,841,351	11,797,615
391.1	Office Furniture & Equipment	10,923,960	5,356,848
391.2	Computers	17,088,286	7,247,842
392	Transportation Equipment	122,249	(182,772)
393	Stores Equipment	-	-
394	Tools, Shop & Garage Equipment	566,780	530,179
395	Laboratory Equipment	-	-
396	Power Operated Equipment	124,897	91,826
397	Communications Equipment	17,456,530	3,810,541
398	Miscellaneous Equipment	11,870	(3,797)
118000-700	Residential Program	123,132	122,851
	Total Common Plant in Service	210,033,482	97,821,016
102	Plant Purchased or Sold	-	
105	Plant Held for Future Use	-	
107	Construction Work in Progress	12,027,406	
108	Retirement Work in Progress		35,604
	Total Common Utility Plant	$222,060,888	$97,856,620

(1) See above for Common Plant classified by account. Common Plant is not allocated to departments.

(2) See above for accumulated depreciation and amortization on Common Plant by utility account. Accumulated depreciation for Common Plant is not allocated to departments.

(3) Expenses other than depreiciation and amortization are not shown above but are allocated thru factors including payroll and gross plant ratios.

403/404 Depreciation/Amortization allocated thru payroll ratios:

Electric	$14,440,508
Gas	2,176,877
Total	$16,617,385

(4) Common Plant classification approved by the Nevada Public Service Commission under order I & S no. 561 December 31, 1969.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				5,114	MW	511,507
2	Reactive Supply and Voltage				5,114	MW	660,493
3	Regulation and Frequency Response				228	MW	252,690
4	Energy Imbalance	43,550,144	KWH	1,223,716	17,049,250	KWH	1,220,450
5	Operating Reserve - Spinning				61	MW	462,001
6	Operating Reserve - Supplement				61	MW	365,506
7	Other				556,632	MWH	149,909
8	Total (Lines 1 thru 7)	43,550,144		1,223,716	17,616,460		3,622,556

Schedule Page: 398 Line No.: 4 Column: g

Amount includes $117,760 imbalance penalty credit.

Schedule Page: 398 Line No.: 7 Column: e

Includes Reactive Supply & Voltage Control of 278,316 MWH and Scheduling System Control & Dispatch of 278,316 MWH.

Schedule Page: 398 Line No.: 7 Column: g

Includes Reactive Supply & Voltage Control of $90,459 and Scheduling System Control & Dispatch of $59,449.

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Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	1,677	3	1900	1,330	239	7	101		
2	February	1,603	8	1900	1,263	232	7	101		
3	March	1,494	6	1900	1,162	231		101		
4	Total for Quarter 1	4,774			3,755	702	14	303		
5	April	1,502	29	1200	1,196	205		101		
6	May	1,621	13	1700	1,279	241		101		
7	June	2,015	28	1700	1,667	232		116		
8	Total for Quarter 2	5,138			4,142	678		318		
9	July	2,077	22	1700	1,720	241		116		
10	August	1,912	20	1600	1,560	236		116		
11	September	1,773	4	1800	1,405	252		116		
12	Total for Quarter 3	5,762			4,685	729		348		
13	October	1,544	1	2000	1,183	236	30	95		
14	November	1,604	21	1800	1,281	198	30	95		
15	December	1,766	9	1900	1,432	208	30	96		
16	Total for Quarter 4	4,914			3,896	642	90	286		
17	Total Year to Date/Year	20,588			16,478	2,751	104	1,255		

Schedule Page: 400 Line No.: 1 Column: c
Change due to updated data

Schedule Page: 400 Line No.: 4 Column: e
Change due to updated data

Schedule Page: 400 Line No.: 4 Column: h
Change due to updated Integrated Demand Loss percentage.

Schedule Page: 400 Line No.: 5 Column: d
Change due to updated data

Schedule Page: 400 Line No.: 8 Column: e
Change due to updated data

Schedule Page: 400 Line No.: 8 Column: h
Change due to updated Integrated Demand Loss percentage.

Schedule Page: 400 Line No.: 10 Column: d
Change due to updated data

Schedule Page: 400 Line No.: 11 Column: c
Change due to updated data

Schedule Page: 400 Line No.: 11 Column: d
Change due to updated data

Schedule Page: 400 Line No.: 12 Column: e
Change due to updated data

Schedule Page: 400 Line No.: 12 Column: h
Change due to updated Integrated Demand Loss percentage.

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Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) ☐ An Original (2) ☒ A Resubmission	04/21/2014	End of 2013/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,151,543
3	Steam	1,902,307			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	630,229
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	403,800
7	Other	3,240,590			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	5,142,897	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	28,460
10	Purchases	4,314,638	27	Total Energy Losses	287,635
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	9,501,667
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	3,242,505			
17	Delivered	3,216,698			
18	Net Transmission for Other (Line 16 minus line 17)	25,807			
19	Transmission By Others Losses	18,325			
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	9,501,667			

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MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	831,126	9,500	1,330	3	1900
30	February	706,789	9,044	1,263	8	1900
31	March	723,978	9,289	1,162	6	1900
32	April	735,466	9,925	1,196	29	1200
33	May	745,275	29,420	1,279	13	1700
34	June	788,917	121,751	1,667	28	1700
35	July	909,461	26,516	1,720	22	1700
36	August	858,682	36,965	1,560	20	1600
37	September	786,558	31,603	1,405	4	1800
38	October	755,552	56,279	1,183	1	2000
39	November	758,060	38,398	1,281	21	1800
40	December	901,793	25,110	1,432	9	1900
41	TOTAL	9,501,657	403,800			

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Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *FT CHURCHILL 1, 2* (b)			Plant Name: *VALMY 1, 2* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	OUTDOOR			OUTDOOR		
3	Year Originally Constructed	1968			1981		
4	Year Last Unit was Installed	1971			1985		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	230.00			283.50		
6	Net Peak Demand on Plant - MW (60 minutes)	220			539		
7	Plant Hours Connected to Load	9086			14864		
8	Net Continuous Plant Capability (Megawatts)	230			284		
9	When Not Limited by Condenser Water	230			284		
10	When Limited by Condenser Water	230			284		
11	Average Number of Employees	30			80		
12	Net Generation, Exclusive of Plant Use - KWh	286692000			1430615000		
13	Cost of Plant: Land and Land Rights	110978			1109664		
14	Structures and Improvements	9013180			63881437		
15	Equipment Costs	55184221			274152077		
16	Asset Retirement Costs	788173			3595055		
17	Total Cost	65096552			342738233		
18	Cost per KW of Installed Capacity (line 17/5) Including	283.0285			1208.9532		
19	Production Expenses: Oper, Supv, & Engr	468894			841525		
20	Fuel	15616983			49979349		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	105801			3544760		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	2487668			3443208		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	111830			694365		
31	Maintenance of Boiler (or reactor) Plant	323666			3424812		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	1599049			636422		
34	Total Production Expenses	20713891			62564441		
35	Expenses per Net KWh	0.0723			0.0437		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS	OIL		GAS	OIL	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	BBL		TONS	BBL	
38	Quantity (Units) of Fuel Burned	3257139	0	0	804219	13628	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1028056	0	0	13372	5834	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.795	0.000	0.000	57.403	143.318	0.000
41	Average Cost of Fuel per Unit Burned	4.795	0.000	0.000	59.697	144.546	0.000
42	Average Cost of Fuel Burned per Million BTU	4.664	0.000	0.000	2.978	18.097	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.054	0.000	0.000	0.034	0.205	0.000
44	Average BTU per KWh Net Generation	11679.862	0.000	0.000	11346.461	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *TRACY 4&5-PIÑON PINE* (b)			Plant Name: *TRACY 8-10* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	GAS TURBINE			GAS TURBINE		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL			CONVENTIONAL		
3	Year Originally Constructed	1996			2008		
4	Year Last Unit was Installed	1996			2008		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	120.00			623.00		
6	Net Peak Demand on Plant - MW (60 minutes)	102			602		
7	Plant Hours Connected to Load	4366			22887		
8	Net Continuous Plant Capability (Megawatts)	120			623		
9	When Not Limited by Condenser Water	120			623		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	291542000			2917001000		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	222989			35351600		
15	Equipment Costs	70293821			414504748		
16	Asset Retirement Costs	414726			337824		
17	Total Cost	70931536			450194172		
18	Cost per KW of Installed Capacity (line 17/5) Including	591.0961			722.6231		
19	Production Expenses: Oper, Supv, & Engr	122898			1533059		
20	Fuel	11776356			98047984		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	655983			7227977		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1168			6885		
30	Maintenance of Structures	195159			745643		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1251758			4890835		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	14003322			112452383		
35	Expenses per Net KWh	0.0480			0.0386		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	2455715	0	0	21560068	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1028067	0	0	1019683	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.795	0.000	0.000	4.548	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.795	0.000	0.000	4.548	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.665	0.000	0.000	4.460	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.040	0.000	0.000	0.034	0.000	0.000
44	Average BTU per KWh Net Generation	8659.610	0.000	0.000	7536.654	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *CLARK MOUNTAIN 3-4* (d)			Plant Name: *TRACY 1,2,3* (e)			Plant Name: (f)			Line No.
COMBUSTION AND GAS			STEAM						1
CONVENTIONAL			OUTDOOR						2
1994			1963						3
1994			1974						4
195.00			243.00			0.00			5
142			106			0			6
845			5344			0			7
195			243			0			8
195			243			0			9
0			243			0			10
0			52			0			11
32047000			185000000			0			12
0			361947			0			13
4764033			10175027			0			14
54166971			76386853			0			15
9436			3050394			0			16
58940440			89974221			0			17
302.2587			370.2643			0			18
13016			97720			0			19
2406852			10374739			0			20
0			0			0			21
0			64633			0			22
0			0			0			23
0			0			0			24
66563			4508			0			25
0			537180			0			26
0			0			0			27
0			0			0			28
76			392			0			29
8172			143582			0			30
0			199493			0			31
106835			0			0			32
0			255254			0			33
2601514			11677501			0			34
0.0812			0.0631			0.0000			35
GAS	OIL		GAS	OIL					36
MCF			MCF						37
482946	0	0	2221578	0	0	0	0	0	38
1027468	0	0	1028661	0	0	0	0	0	39
4.984	0.000	4.670	4.670	0.000	0.000	0.000	0.000	0.000	40
4.984	0.000	0.000	4.670	0.000	0.000	0.000	0.000	4.795	41
4.850	0.000	0.000	4.540	0.000	0.000	0.000	0.000	0.000	42
0.075	0.000	0.000	0.056	0.000	0.000	0.000	0.000	0.000	43
15483.883	0.000	0.000	12352.708	0.000	0.000	0.000	0.000	0.000	44

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Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: c

Valmy is jointly owned with Idaho Power. Each company has a 50% interest. Data reported in column (c) represents Sierra Pacific's share.

Schedule Page: 402 Line No.: 11 Column: b

There are 30 employees including 2 support employees who divide their time between Ft. Churchill and Tracy.

Schedule Page: 403 Line No.: 11 Column: d

There are no employees at Clark Mountain 3-4. Manpower for these units is reported under Tracy 1-3.

Schedule Page: 403 Line No.: 11 Column: e

There are 52 employees including 2 supports who divide their time between Tracy and Ft. Churchill.

Schedule Page: 402.1 Line No.: 11 Column: b

Included in the Tracy 1-3 employee count.

Schedule Page: 402.1 Line No.: 11 Column: c

Included in the Tracy 1-3 employee count.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	INTERNAL COMBUSTION:					
2	BRUNSWICK	1960	6.00	6.0		806,851
3	GABBS	1969				
4						
5	Total Internal Combustion		6.00			806,851
6						
7	RENEWABLES:					
8	OHM-SOLAR	2008	0.75		130	690,611
9	SIERRA PLAZA PV	2007	0.76		39	737,046
10	SIERRA PLAZA WIND	2007	0.10		1	107,617
11						
12	Total Renewables		1.61		170	1,535,274
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
134,476	80,764	4,118	155,879	OIL		2
		33,409				3
						4
134,476	80,764	37,527	155,879			5
						6
						7
920,815				SOLAR		8
969,798				SOLAR		9
1,076,170				WIND		10
						11
2,966,783						12
						13
						14
						15
						16
						17
						18
						19
						20
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						45
						46

Schedule Page: 410 Line No.: 2 Column: a

Gabbs was retired 1/1/13.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	HUMOLDT	IDAHO-NV	345.00	345.00	S-ALTWR	100.74		1
2	VALMY	COYOTECR	345.00	345.00	S-ALTWR	41.31		1
3	TRACY E	VALMY#2	345.00	345.00	S-ALTWR	161.76		1
4	TRACY E	OREANA	345.00	345.00	S-ALTWR	86.01		1
5	OREANA	VALMY	345.00	345.00	S-ALTWR	74.10		1
6	COYOTECR	HUM	345.00	345.00	S-ALTWR	28.62		1
7	VALMY	FALCON	345.00	345.00	S-ALTWR	35.78		1
8	TRACY E	WEST TRACY	345.00	345.00	S-ALTWR	0.90		1
9	VAL RD N	TRACY E	345.00	345.00	S-HFST	19.30		1
10	TRACY E.	NANIWA	345.00	345.00	S-HFST	0.40		1
11	WEST TRACY	MIRA LOMA	345.00	345.00	S-HFST	159.78		1
12	WEST TRACY	MIRA LOMA	345.00	345.00	S-HFST	4.29		1
13	WEST TRACY	MIRA LOMA	345.00	345.00	S-ALTWR	13.00		1
14	HILLTOP	FT SAGE	345.00	345.00	S-HFST	4.22		1
15	HILLTOP	FT SAGE	345.00	345.00	S-HFST	19.56		1
16	HILL TOP	FT SAGE	345.00	345.00	S-HFWD	116.63		1
17	FORT SAGE	BORDERTOWN	345.00	345.00	S-HFWD	32.74		1
18	BORDERTOWN	N. VALLEY	345.00	345.00	S-HFWD	14.40		1
19	345 KV LINE COSTS							
20	345 KV SUBTOTAL					913.54		18
21								
22	UT-NV BOARDER	OSCEOLA	230.00	230.00	S-KFWD	24.75		1
23	MACHACEK	GONDER	230.00	230.00	S-KFWD	66.49		1
24	FRONTIER	MACHACEK	230.00	230.00	S-KFWD	48.67		1
25	FRONTIER	ROUND MT	230.00	230.00	S-KFWD	57.19		1
26	ROUND MT	ANACONDA	230.00	230.00	S-KFWD	26.90		1
27	AUSTIN	FRONTIER	230.00	230.00	S-HFWD	4.20		1
28	AUSTIN	FRONTIER	230.00	230.00	S-SPWD	0.70		1
29	AUSTIN	FRONTIER	230.00	230.00	S-KFWD	13.00		1
30	FT CHURCH	SALTWELLS TP	230.00	230.00	S-KFWD	36.00		1
31	SALT WELLS TAP	SALT WELLS SUB	230.00	230.00	S-HFST	4.90		1
32	SALTWELLS TP	AUSTIN	230.00	230.00	S-KFWD	86.00		1
33	OSCEOLA	GONDER	230.00	230.00	S-KFWD	27.55		1
34	OSCEOLA	SPRING VALLEY	230.00	230.00	S-KFWD	0.08		1
35	230 KV LINE COSTS							
36					TOTAL	2,151.00		150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	230 KV SUBTOTAL					396.43		13
2								
3	CAL SUB	N TRUCKE	120.00	120.00	HFWD	9.35		1
4	CAL SUB	N TRUCKE	120.00	120.00	HFWD	9.53		1
5	SUMMIT 2	CAL SUB	120.00	120.00	HFWD	19.94		1
6	SUMMIT 2	CAL SUB	120.00	120.00	HFWD	6.36		1
7	VAL RD N	VAL ROAD	120.00	120.00	S-DHFWD	0.36		1
8	VAL ROAD	SPAN SPG	120.00	120.00	HFWD	4.52		1
9	VAL ROAD	SPAN SPG	120.00	120.00	HFWD	1.00		1
10	SPAN SPG	TRACY-1	120.00	120.00	HFWD	13.26		1
11	SPAN SPG	TRACY-2	120.00	120.00	HFWD	0.41		1
12	CAL SUB	WA SW STA	120.00	120.00		3.50		1
13	CAL SUB	WA SW STA	120.00	120.00	HFWD	0.73		1
14	WA SW STA	MT ROSE	120.00	120.00	HFWD	4.47		1
15	WA SW STA	RENO	120.00	120.00	RSPWD	6.90		1
16	MT. ROSE	STRUCT #2	120.00	120.00	HFWD	0.06		1
17	STRUCT #2	STRUCT #139	120.00	120.00	HFWD	17.78		1
18	STRUCT #139	CARSON TAP	120.00	120.00	HFWD	1.36		1
19	CARSON TAP	BRUNSWICK	120.00	120.00	HFWD	4.37		1
20	TRACY E	TRW TAP	120.00	120.00	HFWD	8.14		1
21	TRW TAP	BRUNSWICK	120.00	120.00	HFWD	22.86		1
22	BRUNSWCK	109 TAP	120.00	120.00	HFWD	6.78		1
23	109 TAP	Downs	120.00	120.00	HFWD	3.05		1
24	Downs	BUCKEYE	120.00	120.00	HFWD	5.95		1
25	MIRA LMA	BELVISTA	120.00	120.00	S-DSPST	3.60		1
26	CAL SUB	WEST UG	120.00	120.00	HFWD	3.12		1
27	WEST UG (NEXANS)	NORTHWEST	120.00	120.00	u/g	1.28		1
28	EAST UG (PIRELLI)	NORTHWEST	120.00	120.00	u/g	1.68		1
29	EAST UG	NORTHWEST	120.00	120.00	SPWD	1.95		1
30	EAST UG	NORTHWEST	120.00	120.00	SPWD	0.60		1
31	KAISER TP(Pat)	MIRA LMA FLD	120.00	120.00	HFWD	11.87		1
32	MIRA LMA FLD	MIRA LMA	120.00	120.00	DHFWD	1.20		1
33	WINN SUB	STONEHOUSE	120.00	120.00	HFWD	1.10		1
34	WINN SUB	STONEHOUSE	120.00	120.00	HFWD	26.90		1
35	STONEHOUSE	VALMY	120.00	120.00	HFWD	7.38		1
36					TOTAL	2,151.00		150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	EAGLE	DESRT TP	120.00	120.00	HFWD	13.10		1
2	EAGLE	DESRT TP	120.00	120.00	DHFWD	2.03		1
3	DESRT TP	BRADY	120.00	120.00	HFWD	1.36		1
4	BRADY	NGTGLE T	120.00	120.00	HFWD	0.42		1
5	NGTGLE T	LONE MT	120.00	120.00	HFWD	36.24		1
6	NGTGLE T	LONE MT	120.00	120.00	HFWD	2.87		1
7	LONE MT	OREANA	120.00	120.00	HFWD	16.60		1
8	OREANA	STAR PK	120.00	120.00	HFWD	13.78		1
9	FT CHUR	DAYTON TP	120.00	120.00	SPWD	2.70		1
10	FT CHUR	DAYTON TP	120.00	120.00	HFWD/STL	35.30		1
11	FT CHUR	DAYTON TP	120.00	120.00	HFWD	24.90		1
12	DAYTON TP	BRUNSWCK	120.00	120.00	HFWD	6.35		1
13	BUCKEYE	FT CHUR	120.00	120.00	HFWD	37.40		1
14	MT ROSE	STEAMBT	120.00	120.00	HFWD	8.00		1
15	MARK TWAIN	FT CHRCHILL	120.00	120.00	HFWD	26.93		1
16	MARK TWAIN	LINE FOLD	120.00	120.00	S-SPWD	0.30		1
17	STEAMBT	MIRA LMA FLD	120.00	120.00	DHFWD	5.47		1
18	MIRA LMA FLD	MIRA LMA	120.00	120.00	DHFWD	1.20		1
19	GLENDALE	GREG ST	120.00	120.00	SPWD	1.93		1
20	GLENDALE	GREG ST	120.00	120.00	WDSTL	1.67		1
21	VAL ROAD	GLENDALE	120.00	120.00	SPST	4.38		1
22	MARTIS	N TRUCKE	120.00	120.00	RSPWD	1.28		1
23	N TRUCKE	SUMMIT 1	120.00	120.00	HFWD	8.57		1
24	ANACONDA	MILLERS	120.00	120.00	S-HFWD	15.20		1
25	NORTHWEST	PENNYS-TP	120.00	120.00	HFWD	1.75		1
26	PENNYS-TP	Val Rd N	120.00	120.00	HFWD	2.70		1
27	RENO	VAL RD N	120.00	120.00	RSPWD	7.40		1
28	MIRA LMA	GREG ST	120.00	120.00	S-HFWD	6.25		1
29	MIRA LMA	GREG ST	120.00	120.00	S-SPWD	1.32		1
30	TRACY	EAGLE	120.00	120.00	HFWD	19.07		1
31	TRACY	EAGLE	120.00	120.00	DHFWD	2.03		1
32	BELVISTA	GREG ST	120.00	120.00	SPWD	2.37		1
33	BELVISTA	GREG ST	120.00	120.00	UG	0.29		1
34	BELVISTA	GREG ST	120.00	120.00	WDSTL	1.67		1
35	STAR PK	DUN GLEN	120.00	120.00	S-DHFWD	4.89		1
36					TOTAL	2,151.00		150

TRANSMISSION LINE STATISTICS

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6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	STAR PK	DUN GLEN	120.00	120.00	S-HFWD	0.40		1
2	STAR PK	DUN GLEN	120.00	120.00	S-HFWD	15.20		1
3	AIRPORT	RUSTY SPIKE	120.00	120.00	u/g	3.28		1
4	MIRA LOMA	AIRPORT	120.00	120.00	S-SPST	3.60		1
5	MIRA LOMA	AIRPORT	120.00	120.00	UG	2.59		1
6	N.VALLEY	RUSTY SPIKE	120.00	120.00	S-HFWD	0.36		1
7	N.VALLEY	RUSTY SPIKE	120.00	120.00	S-SPWD	0.42		1
8	N.VALLEY	RUSTY SPIKE	120.00	120.00	UG	1.62		1
9	TRACY	KAISER TP(Patrick)	120.00	120.00	HFWD	1.66		1
10	E TRACY	DOVE	120.00	120.00	S-SPWD	0.49		1
11	E TRACY	DOVE	120.00	120.00	S-HFST	13.58		1
12	E TRACY	DOVE	120.00	120.00	S-DHFST	0.65		1
13	E TRACY	DOVE	120.00	120.00	S-SPST	1.35		1
14	DOVE	WESTERN	120.00	120.00	S-HFWD	0.11		1
15	DOVE	WESTERN	120.00	120.00	S-HFWD	0.11		1
16	TRACY	EAST UNDERGROUND	120.00	120.00	S-SPWD	12.40		1
17	UG SECTION (NEXANS)		120.00	120.00	UG	3.22		1
18	WEST UG	SUGARLOAF	120.00	120.00	S-SPWD	0.73		1
19	STEAMBOAT	MARK TWAIN	120.00	120.00	HFWD	13.16		1
20	MARK TWAIN	LINE FOLD	120.00	120.00	S-SPWD	0.29		1
21	DOVE	JAMES HARDIE TAP	120.00	120.00	S-SPWD	0.15		1
22	DOVE	JAMES HARDIE TAP	120.00	120.00	S-SPWD	0.17		1
23	DOVE	JAMES HARDIE TAP	120.00	120.00	S-HFWD	0.50		1
24	JAMES HARDIE TAP	FERNLEY	120.00	120.00	S-HFWD	12.70		1
25	JAMES HARDIE TAP	FERNLEY	120.00	120.00	S-SPWD	4.70		1
26	SUGARLOAF	SILVERLAKE	120.00	120.00	SPWD	10.60		1
27	SUGARLOAF	SILVERLAKE	120.00	120.00	UG	8.00		1
28	DUN GLEN	WINN SUB	120.00	120.00	HFWD	30.36		1
29	Tracy	E Tracy	120.00	120.00	HFWD	0.19		1
30	120 KV LINE COSTS							
31	120 KV SUBTOTAL					671.67		97
32								
33	SUMMIT 3	TDPUD TP	69.00	69.00	SPWD	3.35		1
34	TDPUD TP	TAH-DON TP	69.00	69.00	SPWD	3.79		1
35	TAH-DON TP	TRUCKEE	69.00	69.00	SPWD	2.41		1
36					TOTAL	2,151.00		150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	TRUCKEE	HOBART TP	69.00	69.00	SPWD	3.60		1
2	TRUCKEE	HOBART TP	69.00	69.00	SPWD	1.56		1
3	HOBART TP	STAMPEDE TP	69.00	69.00	SPWD	5.67		1
4	STAMPEDE TP	SIRA BRK	69.00	69.00	SPWD	12.37		1
5	STAMPEDE TP	SIRA BRK	69.00	69.00	SPWD	5.43		1
6	SIRA BRK	LOYALTON	69.00	69.00	SPWD	2.48		1
7	LOYALTON	MARBLE TP	69.00	69.00	SPWD	4.80		1
8	LOYALTON	MARBLE TP	69.00	69.00	SPWD	5.50		1
9	CAL-NEV1	SLVR PK	69.00	69.00	SPWD	5.60		1
10	CAL-NEV1	SLVR PK	69.00	69.00	SPWD	15.00		1
11	CAL-NEV2	SLVR PK	69.00	69.00	SPWD	20.60		1
12	SLVR PK	MIN. TAP	69.00	69.00	SPWD	4.30		1
13	MIN. TAP	COALDALE	69.00	69.00	SPWD	12.30		1
14	COALDALE	MILLERS	69.00	69.00	SPWD	12.80		1
15	MILLERS	W TONOP	69.00	69.00	SPWD	12.50		1
16	W TONOP	TONOPAH	69.00	69.00	SPWD	0.40		1
17	SLVR PK	FOOTCO	69.00	69.00	SPWD	3.40		1
18	FOOTCO	ALKALI	69.00	69.00	SPWD	13.80		1
19	ALKALI	TONOPAH	69.00	69.00	SPWD	17.70		1
20	69 KV LINE COSTS							
21	69 KV SUBTOTAL					169.36		22
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,151.00		150

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2-795 ACSR								1
2-795 ACSR								2
2-795 ACSR								3
2-795 ACSR								4
2-795 ACSR								5
2-795 ACSR								6
2-795 ACSR								7
2-795 ACSR								8
2-795 ACSR								9
954 ACSR								10
2-954 ACSR								11
2-954 ACSR								12
2-795 ACSR								13
2-954 ACSR								14
2-954 ACSR								15
2-954 ACSR								16
2-954 ACSR								17
2-954 ACSR								18
	16,981,320	257,297,537	274,278,857	2,408,783	357,823	397,545	3,164,151	19
	16,981,320	257,297,537	274,278,857	2,408,783	357,823	397,545	3,164,151	20
								21
795 ACSR								22
795 ACSR								23
795 ACSR								24
795 ACSR								25
795 ACSR								26
795 ACSR								27
795 AA								28
795 ACSR								29
795 ACSR								30
795 ACSR								31
795 ACSR								32
795 ACSR								33
795 ACSR								34
	2,811,335	17,610,828	20,422,163	1,045,289	155,277	172,515	1,373,081	35
	38,860,260	376,711,691	415,571,951	5,671,637	842,518	936,047	7,450,202	36

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TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
	2,811,335	17,610,828	20,422,163	1,045,289	155,277	172,515	1,373,081	1
								2
397.5 ACSR								3
4 / 0 CU								4
397.5 ACSR								5
4 / 0 CU								6
1272 AA								7
636 ACSR								8
721 ACAR								9
1020 ACCC								10
2-795 ACSR								11
721 ACAR								12
795 ACSR								13
721 ACAR								14
954 AA								15
954 ACSR								16
431 ACCC								17
954 ACSR								18
636 ACSR								19
636 ACSR								20
636 ACSR								21
397.5 ACSR								22
397.5 ACSR								23
397.5 ACSR								24
954 AA								25
721 ACAR								26
1750 AL								27
1750 AL								28
721 ACAR								29
795 AA								30
637 ACSR								31
636 ACSR								32
556.5 ACSR								33
397.5 ACSR								34
795 ACSR								35
	38,860,260	376,711,691	415,571,951	5,671,637	842,518	936,047	7,450,202	36

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
4 / 0 ACSR								1
397.5 ACSR								2
4 / 0 ACSR								3
4 / 0 ACSR								4
4 / 0 ACSR								5
397.5 ACSR								6
397.5 ACSR								7
397.5 ACSR								8
795 AA								9
795 ACSR								10
636 ACSR								11
636 ACSR								12
636 ACSR								13
636 ACSR								14
636 ACSR								15
795 ACSR								16
636 ACSR								17
636 ACSR								18
954 AA								19
954 AA								20
954 AA								21
795 AA								22
4 / 0 CU								23
795 ACSR								24
721 ACAR								25
954 ACSR								26
795 AA								27
954 ACSR								28
954 AA								29
4 / 0 ACSR								30
397.5 ACSR								31
954 AA								32
1250KCM								33
954 AA								34
397.5 ACSR								35
	38,860,260	376,711,691	415,571,951	5,671,637	842,518	936,047	7,450,202	36

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397.5 ACSR								1
397.5 ACSR								2
1750 kcmil								3
954AA								4
1250 kcm								5
954ACSR								6
954AA								7
1250kcm								8
636 ACSR								9
954 AA								10
954 ACSR								11
954 ACSR								12
954 AA								13
954 AA								14
954 AA								15
954 AA								16
2000 AL								17
954 AA								18
636 ACSR								19
795 ACSR								20
954 AA								21
397.5 AA								22
397.5 ACSR								23
397.5 ACSR								24
397.5 AA								25
954 MCM AA								26
UG 2000 MCM								27
397.5 ACSR								28
1272 AA								29
	18,311,297	94,449,406	112,760,703	1,771,004	263,082	292,286	2,326,372	30
	18,311,297	94,449,406	112,760,703	1,771,004	263,082	292,286	2,326,372	31
								32
4 / 0 CU								33
4 / 0 CU								34
4 / 0 CU								35
	38,860,260	376,711,691	415,571,951	5,671,637	842,518	936,047	7,450,202	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
397.5 ACSR								1
397.5 ACSR								2
397.5 ACSR								3
397.5 ACSR								4
397.5 ACSR								5
397.5 ACSR								6
4 / 0 ACSR								7
2 / 0 ACSR								8
2 / 0 STR CU								9
115 MCM CU								10
4 / 0 STR AL								11
2 / 0 STR CU								12
2 / 0 STR CU								13
2 / 0 STR CU								14
2 / 0 STR CU								15
2 / 0 STR CU								16
1 / 0 STR AL								17
1 / 0 STR AL								18
1 / 0 STR AL								19
	756,308	7,353,920	8,110,228	446,561	66,336	73,701	586,598	20
	756,308	7,353,920	8,110,228	446,561	66,336	73,701	586,598	21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	38,860,260	376,711,691	415,571,951	5,671,637	842,518	936,047	7,450,202	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	ROBINSON SUMMIT	GONDER	4.29	S-HFST		1	1
2	ROBINSON SUMMIT	GONDER	4.22	S-HFST		1	1
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		8.51			2	2

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
2-954 ACSR			345			43,235		43,235	1
2-954 ACSR			345			43,234		43,234	2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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									35
									36
									37
									38
									39
									40
									41
									42
									43
						86,469		86,469	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	26' DROP SUBSTATION	DISTRIBUTION	60.00	2.30	
2	ADOBE SUBSTATION	DISTRIBUTION	120.00	24.90	
3	ADOBE SUBSTATION	DISTRIBUTION	120.00	24.90	
4	AIRPORT SUBSTATION	DISTRIBUTION	24.90	4.16	
5	AIRPORT SUBSTATION	DISTRIBUTION	120.00	24.90	
6	AIRPORT SUBSTATION	DISTRIBUTION	120.00	24.90	
7	ALHAMBRA SUBSTATION	DISTRIBUTION	60.00	4.16	
8	ALKALI SUBSTATION	DISTRIBUTION	55.00	7.20	
9	ALPINE MEADOWS	DISTRIBUTION			
10	AMERICAN CANYON SUBSTATION	DISTRIBUTION	63.00	4.16	
11	ANACONDA SUBSTATION	DISTRIBUTION		24.90	
12	ANACONDA MOLY SUBSTATION	TRANSMISSION	230.00		
13	ANACONDA MOLY SUBSTATION	TRANSMISSION	230.00	125.00	24.90
14	ANTELOPE VALLEY SUBSTATION	DISTRIBUTION	63.00	24.94	2.40
15	ANTELOPE VALLEY SUBSTATION	DISTRIBUTION	63.00	24.90	
16	ATOMIC SUBSTATION	DISTRIBUTION	5.53	4.16	
17	ATOMIC SUBSTATION	DISTRIBUTION	5.53	4.16	
18	AUSTIN SUBSTATION	TRANSMISSION/DIST	230.00		
19	AUSTIN SUBSTATION	TRANSMISSION/DIST	230.00	25.00	13.80
20	AUSTIN SUBSTATION	TRANSMISSION/DIST	230.00		
21	AUSTIN SUBSTATION	TRANSMISSION/DIST	230.00		
22	BANNOCK SUBSTATION	TRANSMISSION	120.00		
23	BARRICK SUBSTATION	TRANSMISSION	120.00	4.16	
24	BATTLE MT SUBSTATION	TRANSMISSION/DIST	60.00	14.40	
25	BATTLE MT SUBSTATION	TRANSMISSION/DIST	65.00	24.90	
26	BATTLE MT SUBSTATION	TRANSMISSION/DIST	120.00	60.00	
27	BATTLE MT SUBSTATION	TRANSMISSION/DIST	60.00		
28	BELLA VISTA SUBSTATION	DISTRIBUTION	120.00	24.90	
29	BELLA VISTA SUBSTATION	DISTRIBUTION	120.00	24.90	
30	BEOWOWE	DISTRIBUTION			
31	BETZE	DISTRIBUTION			
32	BOMB DISPOSAL SUBSTATION	DISTRIBUTION	60.00	34.50	
33	BORDERTOWN SUBSTATION	TRANSMISSION	345.00		
34	BORDERTOWN SUBSTATION	TRANSMISSION	345.00		
35	BOULDER BASIN SUBSTATION	TRANSMISSION	125.00	62.50	
36	BOULDER BASIN SUBSTATION	TRANSMISSION	125.00		
37	BOULDER BASIN SUBSTATION	TRANSMISSION	60.00		
38	BRADYS SUBSTATION	TRANSMISSION/DIST	123.00	24.90	
39	BRIDGE ST. SUBSTATION	DISTRIBUTION	66.00	23.00	13.80
40	BRIDGE ST. SUBSTATION	DISTRIBUTION	66.00	23.00	13.80

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BRUNSWICK SUBSTATION	TRANSMISSION/DIST	120.00	13.20	
2	BRUNSWICK SUBSTATION	TRANSMISSION/DIST	4.36	67.00	
3	BRUNSWICK SUBSTATION	TRANSMISSION/DIST	66.00	24.90	2.40
4	BRUNSWICK SUBSTATION	TRANSMISSION/DIST	125.00	62.50	13.80
5	BRUNSWICK SUBSTATION	TRANSMISSION/DIST	120.00		
6	BUCKEYE SUBSTATION	TRANSMISSION/DIST	120.00	63.00	13.80
7	BUCKEYE SUBSTATION	TRANSMISSION/DIST	120.00	13.20	
8	BUCKEYE SUBSTATION	TRANSMISSION/DIST	60.00		
9	BUCKEYE SUBSTATION	TRANSMISSION/DIST	120.00		
10	BUENA VISTA SUBSTATION	DISTRIBUTION	24.90	12.47	
11	C PUNCH SUBSTATION	DISTRIBUTION	67.00	14.40	24.90
12	CAITHNESS SUBSTATION	DISTRIBUTION	123.00	12.30	
13	CALIFORNIA SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
14	CALIFORNIA SUBSTATION	TRANSMISSION/DIST	120.00	60.00	
15	CALIFORNIA SUBSTATION	TRANSMISSION/DIST	125.00		
16	CALIFORNIA SUBSTATION	TRANSMISSION/DIST	125.00		
17	CANDELARIA SUBSTATION	DISTRIBUTION	120.00	24.90	
18	CARSON SUBSTATION	DISTRIBUTION	67.00	12.47	
19	CARSON SUBSTATION	DISTRIBUTION	120.00	13.20	
20	CARSON SUBSTATION	DISTRIBUTION	120.00	13.20	
21	CARSON SUBSTATION	DISTRIBUTION	120.00		
22	CARSON SUBSTATION	DISTRIBUTION	120.00		
23	CENTERVILLE SUBSTATION	DISTRIBUTION			
24	COAL CANYON SUBSTATION	DISTRIBUTION	63.00	12.47	
25	COALDALE SUBSTATION	DISTRIBUTION	55.00	7.20	
26	COEUR SUBSTATION	DISTRIBUTION	63.00	4.16	
27	CORTEZ SWITCH SUBSTATION	TRANSMISSION	63.00	4.16	
28	COYOTE CREEK SUBSTATION	TRANSMISSION	345.00	125.00	24.90
29	COYOTE CREEK SUBSTATION	TRANSMISSION	345.00	125.00	24.90
30	CRESCENT VALLEY SUBSTATION	DISTRIBUTION	67.00	24.90	
31	CROOK ROAD SUBSTATION	TRANSMISSION	60.00		
32	CURRY STREET SUBSTATION	DISTRIBUTION	67.00	13.20	
33	CURRY STREET SUBSTATION	DISTRIBUTION	67.00	13.20	
34	DAYTON SUBSTATION	DISTRIBUTION	120.00	24.90	7.20
35	DAYTON SWITCH SUBSTATION	TRANSMISSION	120.00		
36	DESERT PEAK SUBSTATION	TRANSMISSION/DIST	120.00	13.80	
37	DONNER LAKE SUBSTATION	DISTRIBUTION			
38	DONNER SUMMIT SUBSTATION	TRANSMISSION	120.00		
39	DOVE SUBSTATION	TRANSMISSION	120.00		
40	DOWNS SUBSTATION	DISTRIBUTION	120.00	13.20	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DRESSER MINERAL SUBSTATION	DISTRIBUTION	60.00	0.48	
2	DRESSER MINERAL SWITCH SUBSTATION	DISTRIBUTION	60.00		
3	DUN GLEN SUBSTATION	TRANSMISSION	120.00		
4	DUTCH FLAT SUBSTATION	DISTRIBUTION	65.35	24.90	
5	DUTCH FLAT SUBSTATION	DISTRIBUTION	60.00	23.90	
6	E. TRACY SUBSTATION	TRANSMSSION	345.00	125.00	24.90
7	E. TRACY SUBSTATION	TRANSMISSION	345.00		
8	E. TRACY SUBSTATION	TRANSMISSION	345.00		
9	EAGLE SUBSTATION	TRANSMISSION/DIST	120.00	12.47	
10	EAGLE SUBSTATION	TRANSMISSION/DIST	120.00	63.00	13.20
11	EAGLE SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
12	EAGLE PITCHER SUBSTATION	DISTRIBUTION	60.00	12.47	
13	EIGHT MILE CREEK	TRANSMISSION	120.00		
14	EL RANCHO SUBSTATION	DISTRIBUTION	22.90	4.36	
15	ELKO SUBSTATION (WEST YARD)	DISTRIBUTION	69.00	2.40	7.50
16	ELKO SUBSTATION (EAST YARD)	DISTRIBUTION	69.00	24.90	5.00
17	EMERSON SUBSTATION	DISTRIBUTION	120.00	13.20	
18	EMPIRE SWITCH STATION	TRANSMISSION	60.00	7.20	12.40
19	EXCELSIOR SUBSTATION	TRANSMISSION	120.00		
20	FAIRVIEW SUBSTATION	DISTRIBUTION	120.00	13.20	
21	FALCON SUBSTATION	TRANSMISSION	345.00	125.00	24.90
22	FALCON SUBSTATION	TRANSMISSON	345.00		
23	FALLON SUBSTATION	DISTRIBUTION	60.00	34.50	
24	FALLON SUBSTATION	DISTRIBUTION	67.00	13.20	
25	FALLON SUBSTATION	DISTRIBUTION	33.00	2.30	
26	FALLON SUBSTATION	DISTRIBUTION	63.00	13.20	
27	FERNLEY SUBSTATION	DISTRIBUTION	67.00	13.20	
28	FLEISH SUBSTATION	DISTRIBUTION	41.40	25.00	
29	FLEISH SUBSTATION	DISTRIBUTION	41.40	25.00	
30	FLEISH SUBSTATION	DISTRIBUTION	41.40	25.00	
31	FLETCHER SUBSTATION	DISTRIBUTION	67.00	14.40	
32	FOOTCO SUBSTATION	DISTRIBUTION	60.00	4.60	
33	FOOTCO SUBSTATION	DISTRIBUTION	60.00	4.80	
34	FRONTIER SUBSTATION	TRANSMISSION	230.00	0.24	
35	FT. CHURCHILL SUBSTATION	TRANSMISSION	120.00	69.00	4.16
36	FT. CHURCHILL SUBSTATION	TRANSMISSION	13.80	4.16	
37	FT. CHURCHILL SUBSTATION	TRANSMISSION	120.00	125.00	13.80
38	FT. CHURCHILL SUBSTATION	TRANSMISSION	13.80	4.16	2.40
39	FT. CHURCHILL SUBSTATION	TRANSMISSION	63.00	24.90	
40	FT. CHURCHILL SUBSTATION	TRANSMISSION	120.00	63.00	13.20

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FT. CHURCHILL SUBSTATION	TRANSMISSION	230.00	125.00	13.80
2	FT. SAGE	TRANSMISSION	345.00		
3	GABBS SUBSTATION	DISTRIBUTION	68.80	34.00	4.16
4	GARLIC SUBSTATION	DISTRIBUTION	63.00	24.90	14.40
5	GERLACH SUBSTATION	DISTRIBUTION	60.00	7.20	
6	GLENBROOK SUBSTATION	DISTRIBUTION	63.00	14.40	2.40
7	GLENDALE SUBSTATION	DISTRIBUTION	120.00	24.90	
8	GLENDALE SUBSTATION	DISTRIBUTION	120.00	24.90	
9	GLENDALE SUBSTATION	DISTRIBUTION		24.90	
10	GOLCONDA SUBSTATION	DISTRIBUTION	63.00	13.20	
11	GOLD QUARRY SUBSTATION	DISTRIBUTION	120.00	24.90	
12	GOLDFIELD SUBSTATION	DISTRIBUTION	67.00	13.20	
13	GONDER SUBSTATION	TRANSMISSION	345.00	230.00	24.90
14	GONDER SUBSTATION	TRANSMISSION	230.00		
15	GONDER SUBSTATION	TRANSMISSION	230.00		
16	GONDER SUBSTATION	TRANSMISSION	345.00		
17	GONDER SUBSTATION	TRANSMISSION	345.00		
18	GONDER SUBSTATION	TRANSMISSION	230.00	69.00	13.80
19	GONDER SUBSTATION	TRANSMISSION	230.00	69.00	13.80
20	GOOSEBERRY MINE SUBSTATION	DISTRIBUTION	62.50	0.48	
21	GRASS VALLEY SUBSTATION	DISTRIBUTION	120.00	60.00	24.90
22	GREG STREET SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
23	GREG STREET SUBSTATION	TRANSMISSION/DIST	120.00	24.90	7.20
24	GREG STREET SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
25	HAWTHORNE SUBSTATION	DISTRIBUTION	60.00	12.47	
26	HAZEN SUBSTATION	DISTRIBUTION	67.00	13.20	
27	HEYBOURNE SUBSTATION	DISTRIBUTION	60.00	13.20	
28	HIGH STREET SUBSTATION	DISTRIBUTION	24.90	4.16	
29	HIGH STREET SUBSTATION	DISTRIBUTION	24.90	4.16	
30	HIGHLAND SUBSTATION	DISTRIBUTION	24.90	4.16	
31	HIGHLAND SUBSTATION	DISTRIBUTION	24.90	4.16	
32	HILLTOP	TRANSMISSION	345.00		
33	HOLCOMB SUBSTATION	DISTRIBUTION	24.90	4.16	
34	HOT SPRINGS SUBSTATION	DISTRIBUTION	60.00	4.16	
35	HUMBOLDT HOUSE SUBSTATION	TRANSMISSION	34.60	6.60	
36	HUMBOLDT SUBSTATION	DISTRIBUTION	345.00	125.00	24.90
37	HUMBOLDT SUBSTATION	DISTRIBUTION	345.00		
38	HUMBOLDT SUBSTATION	DISTRIBUTION	345.00	125.00	24.90
39	HUMBOLDT SUBSTATION	DISTRIBUTION	120.00		
40	HUNTER LAKE SUBSTATION	DISTRIBUTION	24.90	4.16	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HUNTER LAKE SUBSTATION	DISTRIBUTION	24.90	4.16	
2	HUNTER LAKE SUBSTATION	DISTRIBUTION	24.90	4.16	
3	HYCROFT SUBSTATION	DISTRIBUTION			
4	IMCO MILL	DISTRIBUTION	60.00	4.16	
5	IMLAY SUBSTATION	DISTRIBUTION	65.20	13.20	7.62
6	INCLINE SUBSTATION	DISTRIBUTION	120.00	14.40	
7	IRON POINT SUBSTATION	DISTRIBUTION	67.00	7.62	
8	J.C. PENNEYS SUBSTATION	DISTRIBUTION	65.00	12.47	
9	J.C. PENNEYS SUBSTATION	DISTRIBUTION	65.00	12.47	
10	JERRITT SWITCH SUBSTATION	TRANSMISSION	120.00		
11	KAISER SUBSTATION	DISTRIBUTION	120.00	13.80	
12	KAISER SWITCH SUBSTATION	TRANSMISSION	120.00		
13	KENNEMETAL SUBSTATION	DISTRIBUTION	67.00	7.20	
14	KINGSBURY SUBSTATION	DISTRIBUTION	60.00	14.00	
15	KINGSBURY SUBSTATION	DISTRIBUTION	60.00	14.40	
16	KINGSBURY SUBSTATION	DISTRIBUTION	60.00	14.40	
17	KINKAID SUBSTATION	DISTRIBUTION	57.00	12.47	
18	LAHONTON SUBSTATION	TRANSMISSION	60.00		
19	LAST CHANCE SUBSTATION	DISTRIBUTION	120.00	24.90	
20	LIMERICK SUBSTATION	DISTRIBUTION	67.00	13.20	
21	LONE MOUNTAIN SUBSTATION	DISTRIBUTION	120.00	13.20	
22	LONELY SUBSTATION	DISTRIBUTION		12.47	
23	LOVELOCK SUBSTATION	DISTRIBUTION	65.00	13.80	
24	LOWER SMOKY VALLEY SUBSTATION	DISTRIBUTION	55.00	12.00	
25	LOYALTON SUBSTATION	TRANSMISSION	60.00		
26	LUCKY BOY SUBSTATION	DISTRIBUTION	66.00		
27	LUNING SUBSTATION	DISTRIBUTION	36.30	7.20	
28	MACHACEK SUBSTATION	TRANSMISSION	230.00	69.00	13.80
29	MACHACEK SUBSTATION	DISTRIBUTION	230.00	69.00	13.80
30	MAGGIE CREEK SUBSTATION	TRANSMISSION	120.00		
31	MANHATTAN SUBSTATION	DISTRIBUTION	60.00	24.90	
32	MARBLE SUBSTATION	TRANSMISSION	67.00	24.90	
33	MARIGOLD SUBSTATION	DISTRIBUTION	115.00	4.16	
34	MARK TWAIN SUBSTATION	DISTRIBUTION	120.00	24.90	
35	MCCARRAN SUBSTATION	DISTRIBUTION	22.90	4.36	
36	MCCOY SUBSTATION	DISTRIBUTION	63.00	24.90	
37	MILL CITY SUBSTATION	DISTRIBUTION	22.00		
38	MILL IRON SUBSTATION	DISTRIBUTION	67.00	24.90	
39	MILL STREET SUBSTATION	DISTRIBUTION	25.00	4.16	
40	MILL STREET SUBSTATION	DISTRIBUTION	22.90	4.36	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MILLERS SUBSTATION	TRANSMISSION	125.00	62.50	13.80
2	MINA SUBSTATION	DISTRIBUTION	55.00	12.47	
3	MINDEN SUBSTATION	DISTRIBUTION	67.00	13.20	
4	MIRA LOMA SUBSTATION	TRANSMISSION/DIST	345.00	125.00	24.90
5	MIRA LOMA SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
6	MIRA LOMA SUBSTATION	TRANSMISSION/DIST	345.00	125.00	24.90
7	MOANA SUBSTATION	DISTRIBUTION	22.90	4.36	
8	MOANA SUBSTATION	DISTRIBUTION	23.50	4.33	
9	MT. ROSE SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
10	MT. ROSE SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
11	MT. ROSE SUBSTATION	TRANSMISSION/DIST		24.90	
12	MULLER SUBSTATION	DISTRIBUTION	120.00	13.20	
13	NEVADA ST. SUBSTATION	DISTRIBUTION	63.00	12.47	
14	NEVADA CEMENT	DISTRIBUTION	65.20	4.36	
15	NIGHTINGALE SUBSTATION	DISTRIBUTION	120.00	12.47	
16	NORTH TRUCKEE SUBSTATION	TRANSMISSION	125.00	62.50	13.80
17	NORTH VALLEY RD. SUBSTATION	TRANSMISSION	345.00		
18	NORTH VALLEY RD. SUBSTATION	TRANSMISSION	345.00	125.00	24.90
19	NORTH VALLEY RD. SUBSTATION	TRANSMISSION	345.00	120.00	
20	NORTH VALMY SUBSTATION	TRANSMISSION	345.00	125.00	24.90
21	NORTH VALMY SUBSTATION	TRANSMISSION	345.00	125.00	24.90
22	NORTH VALMY SUBSTATION	TRANSMISSION	345.00		
23	NORTH VALMY SUBSTATION	TRANSMISSION	345.00		
24	NORTH VALMY SUBSTATION	TRANSMISSION	120.00	24.90	7.20
25	NORTH VALMY SUBSTATION	TRANSMISSION	345.00		
26	NORTH VALMY SUBSTATION	TRANSMISSION	345.00		
27	NORTH VALMY SUBSTATION	TRANSMISSION	345.00		
28	NORTHWEST SUBSTATION	DISTRIBUTION	120.00	24.90	12.47
29	NORTHWEST SUBSTATION	DISTRIBUTION	120.00	24.90	7.20
30	NORTHWEST SUBSTATION	DISTRIBUTION		24.90	
31	OREANA SUBSTATION	TRANSMISSION	125.00	62.50	13.80
32	OSCEOLA SUBSTATION	TRANSMISSION	230.00		
33	OSGOOD SUBSTATION	DISTRIBUTION	120.00	24.90	
34	OVERLAND SUBSTATION	DISTRIBUTION	120.00	13.20	
35	PARRAN SUBSTATION	DISTRIBUTION	34.60	7.20	
36	PATRICK SUBSTATION	DISTRIBUTION	120.00	24.90	14.40
37	PEGASUS SUBSTATION	DISTRIBUTION	60.00	24.90	
38	PETTIT RANCH SUBSTATION	DISTRIBUTION	60.00	2.30	
39	PETTIT RANCH SUBSTATION	DISTRIBUTION	67.00		
40	PICKARD SUBSTATION	DISTRIBUTION	22.90	4.36	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PINENUT SUBSTATION	DISTRIBUTION	63.00	13.80	
2	PIT SUBSTATION	DISTRIBUTION	120.00	4.16	
3	PURGATORY SUBSTATION	DISTRIBUTION	60.00		
4	PYRAMID SUBSTATION	DISTRIBUTION	22.90	4.39	
5	PYRAMID SUBSTATION	DISTRIBUTION	22.90	4.36	
6	QUARRY SUBSTATION	DISTRIBUTION	67.00	13.20	
7	RAGTOWN SUBSTATION	DISTRIBUTION	60.00		
8	RAILROAD SUBSTATION	DISTRIBUTION	66.00	7.20	
9	RAIN SUBSTATION	DISTRIBUTION	24.90	4.16	
10	RAY COUCH SUBSTATION	DISTRIBUTION	67.00	13.20	
11	RAY COUCH SUBSTATION	DISTRIBUTION	63.00	13.20	
12	RED HOUSE SUBSTATION	DISTRIBUTION	120.00	14.40	14.40
13	REESE RIVER SUBSTATION	DISTRIBUTION	63.00	24.90	
14	RENO SUBSTATION	DISTRIBUTION	23.50	4.36	
15	RENO SUBSTATION	DISTRIBUTION	24.90	4.16	
16	RENO SUBSTATION	DISTRIBUTION	120.00	24.90	7.20
17	RENO SUBSTATION	DISTRIBUTION	120.00	24.90	7.20
18	RENO SUBSTATION	DISTRIBUTION		24.90	
19	RENO SUBSTATION	DISTRIBUTION		24.90	
20	ROBINSON SUMMIT SUBSTATION	TRANSMISSION	525.00	345.00	34.50
21	ROCHESTER SUBSTATION	DISTRIBUTION	60.00		
22	ROSE CREEK SUBSTATION	DISTRIBUTION	67.00	24.90	
23	ROUND HILL SUBSTATION	DISTRIBUTION	120.00	14.40	5.20
24	ROUND MOUNTAIN SUBSTATION	DISTRIBUTION	230.00	24.90	
25	RUSTY SPIKE SUBSTATION	DISTRIBUTION	120.00	24.90	14.40
26	RYE PATCH SUBSTATION	DISTRIBUTION	60.00	2.40	
27	SALT WELLS SUBSTATION	TRANSMISSION	230.00	13.80	
28	SANDIA SUBSTATION	DISTRIBUTION	125.00	62.50	13.80
29	SANDIA SUBSTATION	DISTRIBUTION	66.00	13.80	
30	SANTA FE SUBSTATION	DISTRIBUTION	120.00	14.40	
31	SCHEELITE SUBSTATION	DISTRIBUTION	60.00	12.50	2.40
32	SETTY SUBSTATION	DISTRIBUTION	63.00	24.90	
33	SILVER LAKE SUBSTATION	DISTRIBUTION	66.00	23.00	
34	SILVER LAKE SUBSTATION	DISTRIBUTION	120.00	63.00	
35	SILVER LAKE SUBSTATION	DISTRIBUTION	120.00	24.90	14.40
36	SILVER PEAK SUBSTATION	TRANSMISSION	60.00	60.00	
37	SILVER PEAK SUBSTATION	TRANSMISSION	67.00		
38	SILVER PEAK SUBSTATION	TRANSMISSION	60.00	24.90	
39	SILVER PEAK SUBSTATION	TRANSMISSION	60.00	60.00	
40	SILVER PEAK SUBSTATION	TRANSMISSION	55.00		

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SILVER SPRINGS SUBSTATION	DISTRIBUTION	67.00	13.20	
2	SMITH VALLEY SUBSTATION	DISTRIBUTION	23.00		
3	SONOMA HEIGHTS SUBSTATION	DISTRIBUTION	65.00	24.90	
4	SOUTH SIDE SUBSTATION	DISTRIBUTION	34.50	4.16	
5	SPANISH SPRINGS SUBSTATION	DISTRIBUTION	120.00	24.90	
6	SPANISH SPRINGS SUBSTATION	DISTRIBUTION	120.00	24.90	
7	SPANISH SPRINGS SUBSTATION	DISTRIBUTION		24.90	
8	SPARKS INDUSTRIAL SUBSTATION	DISTRIBUTION	22.00	4.33	
9	STAGECOACH SUBSTATION	DISTRIBUTION	63.00	24.90	7.20
10	STAR PEAK SUBSTATION	TRANSMISSION	120.00		
11	STEAD SUBSTATION	DISTRIBUTION	63.00	24.90	13.80
12	STEAD SUBSTATION	DISTRIBUTION	66.00	23.00	13.80
13	STEAD SUBSTATION	DISTRIBUTION	22.90	4.36	
14	STEAMBOAT SUBSTATION	TRANSMISSION/DIST	120.00	24.90	7.20
15	STEAMBOAT SUBSTATION	TRANSMISSION/DIST	120.00	24.90	12.47
16	STEAMBOAT SUBSTATION	TRANSMISSION/DIST		24.90	
17	STICKLEMAN SUBSTATION	DISTRIBUTION	55.00	12.47	
18	STONE CABIN SUBSTATION	DISTRIBUTION	55.00	0.21	
19	SUGARLOAF SUBSTATION	DISTRIBUTION	120.00	24.90	
20	SUTRO SUBSTATION	DISTRIBUTION	22.90	4.36	
21	SWEETWATER SUBSTATION	DISTRIBUTION	60.00	24.90	
22	T LAZY S SUBSTATION	DISTRIBUTION	63.00	24.90	
23	TABLE MOUNTAIN SUBSTATION	TRANSMISSION	120.00		
24	TENABO SWITCHING STATION	TRANSMISSION	60.00		
25	THORNE SUBSTATION	TRANSMISSION	125.00	62.50	13.80
26	THORNE SUBSTATION	TRANSMISSION	125.00	62.50	13.80
27	TIADS INTERCONNECTION	DISTRIBUTION			
28	TIADS SUBSTATION	TRANSMISSION			
29	TITANIUM WEST #1 SUBSTATION	DISTRIBUTION	67.00	4.16	
30	TITANIUM WEST #2 SUBSTATION	DISTRIBUTION	67.00	4.16	
31	TONKIN SPRINGS SUBSTATION	DISTRIBUTION	63.00	4.16	
32	TOPAZ SUBSTATION	DISTRIBUTION	22.90	13.20	
33	TOULON SUBSTATION	DISTRIBUTION	67.00	7.60	
34	TRACY #1 SUBSTATION	DISTRIBUTION	120.00	2.40	
35	TRACY #1 SUBSTATION	DISTRIBUTION	120.00	13.80	
36	TRACY #2 SUBSTATION	DISTRIBUTION	2.40	0.48	
37	TRACY #2 SUBSTATION	DISTRIBUTION	120.00	13.80	
38	TRACY #3 SUBSTATION	DISTRIBUTION	120.00	4.16	
39	TRACY #3 SUBSTATION	DISTRIBUTION	13.80	4.16	
40	TRACY #3 SUBSTATION	DISTRIBUTION	120.00	13.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TRACY 120 YARD SUBSTATION	TRANSMISSION	125.00	62.50	13.80
2	TRACY 120 YARD SUBSTATION	TRANSMISSION	63.00	23.00	13.80
3	TRI CENTER	DISTRIBUTION	345.00		
4	TROLLEY SWITCH STATION	TRANSMISSION	120.00		
5	TRUCKEE SUBSTATION	DISTRIBUTION	61.43	14.40	
6	TRUCKEE SUBSTATION	DISTRIBUTION	60.00		
7	TYBO SUBSTATION	DISTRIBUTION	63.00	4.16	
8	US GYPSUM SUBSTATION	DISTRIBUTION	64.00	0.48	
9	UNIVERSITY SUBSTATION	DISTRIBUTION	22.90	4.36	
10	UNIVERSITY SUBSTATION	DISTRIBUTION	22.90	4.36	
11	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	125.00	68.75	15.00
12	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	125.00	68.75	15.00
13	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	125.00	68.75	15.00
14	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
15	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	120.00	24.90	6.95
16	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	23.50	4.16	
17	VALLEY ROAD SUBSTATION	TRANSMISSION/DIST	24.90		
18	VERDI SUBSTATION	DISTRIBUTION	24.90	2.30	
19	VIRGINIA CITY SUBSTATION	DISTRIBUTION	63.00	24.90	4.80
20	WADSWORTH SUBSTATION	TRANSMISSION	65.20	13.20	
21	WELLS SUBSTATION	DISTRIBUTION			
22	WEST 7TH ST. SUBSTATION	DISTRIBUTION	24.90	4.36	
23	WEST SIDE SUBSTATION	DISTRIBUTION	63.00	13.20	
24	WEST TONOPAH SUBSTATION	DISTRIBUTION	60.00	12.47	
25	WEST TRACY SUBSTATION	TRANSMISSION	345.00	18.00	
26	WEST TRACY SUBSTATION	TRANSMISSION	345.00	18.00	
27	WEST TRACY SUBSTATION	TRANSMISSION	345.00	18.00	
28	WHEELER SUBSTATION	DISTRIBUTION	22.90	4.36	
29	WINNEMUCCA G.T. SUBSTATION	TRANSMISSION	67.00	13.80	
30	WINNEMUCCA SUBSTATION	TRANSMISSION/DIST	120.00	24.90	
31	WINNEMUCCA SUBSTATION	TRANSMISSION/DIST	120.00	62.50	13.80
32	WINNEMUCCA SUBSTATION	TRANSMISSION/DIST	120.00		
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
30	1					2
34	1					3
5	1					4
47	1					5
60	1					6
1	3					7
167	1					8
						9
7	1					10
28	1					11
			Reactor	1	15	12
150	1		Capacitor	1	7	13
9	1					14
14	1					15
3	3					16
1		1				17
			Line Reactor	1	15	18
22	1		Tertiary Reactor	1	8	19
			Line Reactor	1	25	20
			Capacitor	1	45	21
						22
12	1					23
7	1					24
5	1					25
67	1					26
			Capacitor	1	7	27
60	1					28
42	1					29
						30
						31
1	1					32
			Phase Shifter	1	300	33
			Shunt Reactor	1	35	34
24	1					35
			Capacitor	1	16	36
	1					37
6	1					38
10	1					39
13	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
22	1					1
5	1					2
14	1					3
75	1					4
			Capacitor	1	19	5
47	1					6
25	1					7
			Capacitor	1	6	8
			Capacitor	1	20	9
24	3					10
1	1					11
33	1					12
28	1					13
15	1					14
			Phase Shifter	1	150	15
			Phase Shifter	1	150	16
7	1					17
6	1					18
25	1					19
25	1					20
			Capacitor	1	16	21
			Capacitor	1	20	22
						23
	1					24
	3					25
11	1					26
5	1		Capacitor	2	2	27
150	1					28
150	1					29
2	3					30
						31
14	1					32
11	1					33
14	1					34
						35
25	1					36
						37
						38
						39
28	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1	1					1
						2
						3
11	1					4
14	1					5
280	1		Tertiary Reactor	1	45	6
			Line Reactor	1	35	7
			Line Reactor	1	35	8
14	1					9
84	1					10
28	1					11
3	1					12
			Capacitor	1	12	13
5	1					14
1	1					15
2						16
28	1					17
	1					18
120			Breaker	1	120	19
28	1					20
150	1					21
			Reactor	1	48	22
12	3					23
7	1					24
1	3					25
14	1					26
5	1					27
1	1					28
1	1					29
1	1					30
2	3					31
1	3					32
1	3					33
	1					34
11	1					35
7	1					36
150	1					37
7	1					38
5	1					39
56	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
150	1					1
			Line Reactor	1	35	2
5	3					3
5	1					4
	1					5
5	1					6
40	1					7
60	1					8
			Capacitor	1	9	9
5	1					10
20	2					11
1	3					12
300	1		Tertiary Capacitor	2	38	13
			Reactor	1	15	14
			Reactor	1	30	15
			Reactor	1	48	16
			Reactor	1	48	17
	1		Tertiary Reactor	1	8	18
	1		Tertiary Reactor	1	8	19
3	1					20
28	1					21
47	1					22
47	1					23
60	1					24
13	1					25
1	3					26
40	1					27
3	1					28
3	1					29
3	1					30
3	1					31
			Line Reactor	1	35	32
8	3					33
3	1					34
	1					35
150	1		Tertiary Reactor	1	21	36
			Line Reactor	1	48	37
150	1					38
			Capacitor	1	54	39
3	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
5	1					2
						3
3	1					4
3	3					5
34	1					6
100	1					7
7	1					8
7	1					9
						10
14	1					11
						12
3	3					13
4	1					14
13	1					15
4	1					16
	3					17
			Capacitor	1	5	18
36	1					19
	3					20
5						21
28	1					22
3	1					23
	3					24
			Capacitor	1	3	25
	1					26
1	3					27
45	1		Tertiary Reactor	1	8	28
45	1					29
			Capacitor	1	12	30
4	1					31
1	3					32
1	3					33
47	1					34
5	1					35
5	1					36
	3					37
	3					38
4	1					39
3	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
36	1					1
	3					2
9	1					3
280	1		Tertiary Reactor	1	45	4
60	1					5
280	1					6
3	1					7
2	1					8
40	1					9
34	1					10
			Capacitor	1	6	11
28	1					12
8	1					13
11	2					14
25	1					15
75	1					16
			Line Reactor	1	35	17
280	1					18
280	1					19
	1					20
	1					21
			Line Reactor	1	48	22
			Line Reactor	1	35	23
	1					24
			Line Reactor	1	35	25
			Line Reactor	1	35	26
			Line Reactor	1	35	27
47	1					28
47	1					29
			Capacitor	1	9	30
39	1					31
			Line Reactor	1	-25	32
14	1					33
28	1					34
	1					35
60	1					36
3	1					37
	1					38
2		1				39
9	3					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
29	1					1
12	1					2
						3
3	1					4
3	1					5
1	1					6
						7
	1					8
5	1					9
6	1					10
14	1					11
	1					12
7	1					13
7	1					14
7	1					15
47	1					16
47	1					17
			Capacitor	1	10	18
			Capacitor	1	12	19
525	2					20
						21
7	1					22
25	1					23
10	2					24
47	1					25
	2					26
						27
28	1					28
2	1					29
7	1					30
	3					31
14	1					32
13	1					33
75	1					34
47	1					35
15	1		Phase Shifter	1	15	36
2	1					37
7	1					38
15	1		Phase Shifter	1	15	39
			Capacitor	1	4	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Sierra Pacific Power Company d/b/a NV Energy	(1) [ ] An Original (2) [X] A Resubmission	04/21/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
7	1					1
						2
8	1					3
2	1					4
60	1					5
60	1					6
			Capacitor	2	10	7
2	1					8
34	1					9
						10
14	1					11
10	1					12
5	1					13
47	1					14
47	1					15
			Capacitor	1	10	16
	3					17
						18
60	1					19
5	1					20
1	3					21
5	1					22
						23
						24
36	1					25
22	1					26
						27
						28
5	1					29
4	2					30
7	1					31
3	1					32
	3					33
6	1					34
59	1					35
1	1					36
81	1					37
8	1					38
7	1					39
140	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
75	1					1
10	1					2
						3
						4
5	1					5
			Capacitor	1	8	6
2	1					7
2	1					8
5	1					9
5	1					10
19	1					11
19	1					12
19	1					13
47	1					14
47	1					15
6	1					16
			Capacitor	1	8	17
3	1					18
6	1					19
5	1					20
						21
5	1					22
8	1					23
7	1					24
200	1					25
200	1					26
200	1					27
5	1					28
15	1					29
28	1					30
39	1					31
			Capacitor	1	15	32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 1 Column: b

All Substations are Unattended.

Schedule Page: 426 Line No.: 1 Column: c

Columns c, d, and e are at the transformer level to distinguish between different voltage transformers.

Schedule Page: 426 Line No.: 1 Column: f

Capacity Summary by Function	Total Capacity in MVa
Distribution	1,754
Transmission	2,138
Both	584
Total	4,476

Column f is at the substation level and is the max MVa the substation is capable of handling. Total susbtations are as follows:

Transmission:	52
Distribution:	151
Transmission & Distribution:	13
Distribution, customer owned:	7
Total:	223

Schedule Page: 426 Line No.: 30 Column: b

CUSTOMER OWNED

Schedule Page: 426 Line No.: 31 Column: b

CUSTOMER OWNED

Schedule Page: 426.1 Line No.: 12 Column: b

CUSTOMER OWNED

Schedule Page: 426.3 Line No.: 11 Column: b

CUSTOMER OWNED

Schedule Page: 426.4 Line No.: 26 Column: b

CUSTOMER OWNED

Schedule Page: 426.8 Line No.: 3 Column: b

CUSTOMER OWNED

Schedule Page: 426.8 Line No.: 21 Column: b

CUSTOMER OWNED

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	A & G Salaries	NV Energy, Inc.	920	7,228,425
3	Salary Overheads	NV Energy, Inc.	920,926,408	9,977,907
4	Employee Expenses Incurred	NV Energy, Inc.	921	1,516,045
5	on behalf of Affiliate-Sierra Pacific Power			
6	Sub Total			18,722,377
7				
8	A & G Salaries	Nevada Power Company	920	11,465,715
9	Salary Overheads	Nevada Power Company	920,926,408	11,670,896
10	Employee Expenses Incurred	Nevada Power Company	921	666,707
11	on behalf of Affiliate-Sierra Pacific Power			
12	Sub Total			23,803,318
13	Refer to footnote on line 37 for agreement between			
14	companies and service/allocation descriptions.			
15	Grand Total			42,525,695
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	A & G Salaries	Nevada Power Company	920	9,761,107
22	Salary Overheads	Nevada Power Company	920,926,408	11,261,481
23	Employee Expenses Incurred	Nevada Power Company	921	589,551
24	on behalf of Affiliate			
25	Sub Total			21,612,139
26				
27	A & G Salaries	NV Energy, Inc.	920	28,319
28	Salary Overheads	NV Energy, Inc.	920,926,408	-501,482
29	Employee Expenses Incurred	NV Energy, Inc.	921	7,680
30	on behalf of Affiliate			
31	Sub Total			-465,483
32	Refer to footnote on line 37 for agreement between			
33	companies and service/allocation descriptions.			
34	Grand Total			21,146,656
35				
36				
37	Service Agreement Footnote			
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 37 Column: a

Charges to and from Affiliated Companies result from direct charges as well as common costs that are allocated using various methodologies. These charges are governed by a Master Service Agreement. See below for allocation information.

EXHIBIT II

Function	Allocation Factors
Accounting	Equity Ratio/ Composite Ratio
Administrative Support	Equity Ratio/ Composite Ratio
Business Support Services	Equity Ratio/ Composite Ratio
Community and Economic Development	Composite Ratio
Corporate Communications	Equity Ratio/ Composite Ratio
Credit & Risk Management	Equity Ratio/ Composite Ratio
Customer Services	Customer Ratio/Meter Ratio
Design Engineering	Payroll Ratio
Bulk Power Transport	Payroll Ratio
Environmental	Payroll Ratio
Executive/Senior Management	Equity Ratio/ Composite Ratio
Facilities and Real Estate	Equity Ratio/ Composite Ratio
Finance and Treasury	Equity Ratio/ Composite Ratio
Generation Support Services	Payroll Ratio
Governmental Affairs	Composite Ratio/Payroll Ratio
Human Resources	Composite Ratio
	Payroll Ratio
	Equity Ratio
Information Systems	Equity Ratio/ Composite Ratio
Internal Audit	Equity Ratio/ Composite Ratio
Legal	Equity Ratio/ Composite Ratio
Rates and Regulation	Composite Ratio/Payroll Ratio
Renewable Energy Services	Payroll Ratio
Resource Optimization	Payroll Ratio
Shareholder Relations	Equity Ratio
Substation Engineering and Support	Payroll Ratio
Supply Chain	Equity Ratio/ Composite Ratio
Transmission Support Services	Payroll Ratio
Transportation	Composite Ratio

EXHIBIT III

Ratio	Based On
Equity Ratio	The common equity at the end of the immediately preceding year, the numerator of which is for an Affiliate and the denominator of which is for all the Affiliates. This ratio will be determined annually, or at such time as may be required due to significant changes. In the absence of equity at any affiliate, long and short term debt will be substituted in both the numerator and denominator
Composite Ratio	--Year End Customers The total electric customers (and/or gas, or residential, business and large commercial and industrial customers where applicable) at the end of the immediately preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.
	--Gross Plant (exc. Common, Leased) CWIP The sum of the total fixed assets at the end of the immediate preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.
	--O&M (exc. Payroll, A&G Common, Fuel) The total operation and maintenance expense excluding payroll, common administrative and general expenses, and fuel at the end of the immediate preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.
	--O&M Payroll The total operation and maintenance payroll expense at the end of the immediate preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.
Customer Ratio	The total electric customers (and/or gas, or residential, business and large commercial and industrial customers where applicable) at the end of the immediately preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.
Meter Ratio	The total meters in service at the end of the immediate preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.
Payroll Ratio	The total operation and construction payroll expense excluding common administrative and general expenses at the end of the immediate preceding year, the numerator of which is for an Affiliate and the denominator of which is for all Affiliates. This ratio will be determined annually, or at such time as maybe required due to a significant change.

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