UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2013

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from _____ to _____

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
000-00508	**SIERRA PACIFIC POWER COMPANY** **(A Nevada Corporation)** **6100 Neil Road** **Reno, Nevada 89511**	**88-0044418**

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $3.75 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes ☐ No ☒
All shares of outstanding common stock of Sierra Pacific Power Company are held by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of MidAmerican Energy Holdings Company. As of February 28, 2014, 1,000 shares of common stock, $3.75 par value, were outstanding**.**

Sierra Pacific Power Company meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

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Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 1 through 4, Part II - Items 5 through 7A and Items 9 through 9B, and Part III - Item 14, the following terms have the definitions indicated.

Sierra Pacific Power Company and Related Entities

Company	Sierra Pacific Power Company and its subsidiaries
MEHC	MidAmerican Energy Holdings Company
NV Energy	NV Energy, Inc.
Berkshire Hathaway	Berkshire Hathaway Inc.
Nevada Power	Nevada Power Company, an electric utility wholly owned by NV Energy
Ft. Churchill Generating Station	226-megawatt generating facility in Nevada
ON Line	500-kilovolt transmission line connecting the Company and Nevada Power
NV Energize	NV Energy project which includes advanced meter infrastructure, Smart Grid Technology and meter data management
Tracy Generating Station	889-megawatt generating facility in Nevada
Valmy Generating Station	522-megawatt generating facility in Nevada

Certain Industry Terms

AFUDC	Allowance for Funds Used During Construction
Dth	Decatherms
EEIR	Energy Efficiency Implementation Rate
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
GHG	Greenhouse Gases
GWh	Gigawatt Hours
IRP	Integrated Resource Plan
kV	Kilovolt
MATS	Mercury and Air Toxics Standards
MW	Megawatts
MWh	Megawatt Hours
NERC	North American Electric Reliability Corporation
PUCN	Public Utilities Commission of Nevada
RPS	Renewable Portfolio Standard
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan
WECC	Western Electricity Coordinating Council

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the Company's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of the Company and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in, and compliance with, laws and regulations, including reliability and safety standards, affecting the Company's operations or related industries;

- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce generating facility output, accelerate generating facility retirements or delay generating facility construction or acquisition;

- the outcome of rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and the Company's ability to recover costs in rates in a timely manner;

- changes in economic, industry or weather conditions, as well as demographic trends, new technologies and various conservation, energy efficiency and distributed generation measures and programs, that could affect customer growth and usage, electricity and natural gas supply or the Company's ability to obtain long-term contracts with customers and suppliers;

- a high degree of variance between actual and forecasted load or generation that could impact the Company's hedging strategy and the cost of balancing its generation resources with its retail load obligations;

- performance and availability of the Company's generating facilities, including the impacts of outages and repairs, transmission constraints, weather and operating conditions;

- changes in prices, availability and demand for wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;

- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the Company's control or by a breakdown or failure of the Company's operating assets, including storms, floods, fires, earthquakes, explosions, landslides, litigation, wars, terrorism and embargoes;

- the financial condition and creditworthiness of the Company's significant customers and suppliers;

- changes in business strategy or development plans;

- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for the Company's credit facilities;

- changes in the Company's credit ratings;

- the impact of certain contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of certain contracts;

- the impact of inflation on costs and the Company's ability to recover such costs in rates;

- increases in employee healthcare costs, including the implementation of the Affordable Care Act;

- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements related to the Company's participation in NV Energy's benefit plans;

- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;

- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the Company's consolidated financial results; and

- other business or investment considerations that may be disclosed from time to time in the Company's filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in Item 1A and other discussions contained in this Form 10-K. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing factors should not be construed as exclusive.

PART I

Item 1. Business

General

The Company is a wholly owned subsidiary of NV Energy, a holding company that also owns Nevada Power and certain other subsidiaries. NV Energy is an indirect wholly owned subsidiary of 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.

On December 19, 2013, the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013 ("Merger Agreement"), 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 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 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.

The Company's principal executive offices are located at 6100 Neil Road, Reno, Nevada 89511, and its telephone number is (775) 834-4011. The Company was incorporated in 1912 under the laws of the state of Nevada.

Operations

The Company is a United States regulated electric and natural gas utility company serving 0.3 million retail electric customers, including residential, commercial and industrial customers, and 0.2 million retail and transportation natural gas customers in northern Nevada. The Company is principally engaged in the business of generating, transmitting, distributing and selling electricity over a service territory covering approximately 41,000 square miles and in distributing, selling and transporting natural gas in an area of about 800 square miles in Reno and Sparks. The Company has two segments: its regulated electric utility operations and its regulated natural gas operations. Principal industries served by the Company include gaming, recreation, warehousing, manufacturing and government. In addition to retail sales and natural gas transportation, the Company sells electricity and natural gas to other utilities, municipalities and energy marketing companies on a wholesale basis.

Employees

As of December 31, 2013, the Company had approximately 1,000 employees, of which approximately 600 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

Regulated Electric Operations

Customers

Electricity sold to retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2013		2012		2011	
GWh sold:						
Residential	2,370	26%	2,284	26%	2,231	26%
Commercial	2,948	33	2,930	33	2,852	33
Industrial	2,818	31	2,707	30	2,565	30
Total retail	8,136	90	7,921	89	7,648	89
Wholesale	891	10	1,025	11	920	11
Total GWh sold	9,027	100%	8,946	100%	8,568	100%
Average number of retail customers (in thousands):						
Residential	281	86%	279	86%	277	86%
Commercial	46	14	45	14	45	14
Total	327	100%	324	100%	322	100%

Customer Usage and Seasonality

In addition to the variations in weather from year to year, fluctuations in economic conditions within the service territory and elsewhere can impact customer usage, particularly for gaming customers.

There are seasonal variations in the Company's electric business that are principally related to the use of electricity for air conditioning and the related effects of weather. Typically, 35-37% of the Company's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak customer demand on the Company's electric system occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On July 22, 2013, the Company's retail customer usage of electricity caused an hourly peak demand of 1,720 MW on the Company's electric distribution system.

Generating Facilities and Fuel Supply

The Company has ownership interests in a diverse portfolio of generating facilities. The following table presents certain information regarding the Company's owned generating facilities as of December 31, 2013:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
COAL - Valmy	Valmy, NV	Coal	1981-1985	522	261
NATURAL GAS:					
Tracy	Sparks, NV	Natural Gas/Oil	1963-2008	889	889
Ft. Churchill	Yerington, NV	Natural Gas/Oil	1968-1971	226	226
Clark Mountain combustion turbines	Sparks, NV	Natural Gas/Oil	1994	132	132
				1,247	1,247
Total available generating capacity				1,769	1,508

(1) Facility Net Capacity represents summer peak ratings. Net Owned Capacity indicates the Company's ownership of Facility Net Capacity.

The following table shows the percentages of the Company's total energy supplied by energy source for the years ended December 31:

	2013	2012	2011
Natural gas/oil	40%	44%	37%
Coal	15	11	14
Total energy generated	55	55	51
Energy purchased - short-term contracts and other	4	10	14
Energy purchased - long-term contracts	41	35	35
	100%	100%	100%

The percentage of the Company's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. When factors for one energy source are less favorable, the Company must place more reliance on other energy sources. As long as the Company's purchases are deemed prudent by the PUCN, through its annual prudency review, the Company is permitted to recover the cost of fuel and purchased power. The Company also has the ability to reset quarterly base tariff energy rates based on the last twelve months fuel costs and purchased power and to reset quarterly deferred energy annual adjustments.

The Company has entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing renewable resources and coal with a total nameplate capacity of 447 MW and contract termination dates ranging from 2016 to 2039. Included in these contracts are 232 MW of nameplate capacity of renewable energy.

To secure natural gas supplies for the generating facilities that the Company either owns or has under long-term contract (tolling arrangements), the Company contracts for firm winter, summer, and annual natural gas supplies with numerous domestic and Canadian suppliers. In 2013, natural gas supply net purchases averaged 127,714 Dth per day, with the winter period contracts averaging 146,826 Dth per day and the summer period contracts averaging 108,866 Dth per day. The Company believes supplies from these sources are presently adequate and available to meet its needs.

The Company contracts for firm natural gas pipeline capacity to transport natural gas from production areas to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems. The Company utilizes natural gas storage leased from interstate pipelines to meet retail customer requirements and to manage the daily changes in demand due to changes in weather and other usage factors. The storage natural gas is typically replaced during off-peak months when demand for natural gas is historically lower than during the heating season.

The Company has a long-term coal contract with Black Butte Coal Company for the Valmy Generating Station, which expires December 31, 2015. This contract represents 55% of the current forecasted coal requirements of Valmy Generating Station for 2014. If additional coal supply is needed for 2014, the Company will rely on spot market solicitations. The Company regularly monitors the western coal market for opportunities to enhance its coal supply portfolios. The Company has take or pay transportation services contracts with Union Pacific Railroad Company that extend through 2014 and provide for unit train coal deliveries from various mines in Utah, Colorado and Wyoming as well as from the Provo, Utah interchange to the Valmy Generating Station near Battle Mountain, Nevada.

Transmission and Distribution

The Company's transmission system is part of the Western Interconnection, the regional grid in the Western United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The Company's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customer load requirements. The Company's transmission and distribution systems included approximately 2,200 miles of transmission lines and 200 substations as of December 31, 2013.

On December 31, 2013, the Company along with Nevada Power 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 Company's system and the Harry Allen substation on Nevada Power'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.

Future Generation

The Company files IRPs every three years, and as necessary, may file amendments to its IRPs. IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. IRPs develop a comprehensive, integrated plan that considers customer energy requirements and propose the resources to meet those requirements in a manner that is consistent with prevailing market fundamentals. The ultimate goal of the IRPs is to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of the Company's customers. Projects approved through the IRP process still remain subject to reasonableness review by the PUCN.

Energy Supply Planning

The energy supply function at the Company is responsible for the operation of the Company's owned generation, the procurement of all fuels and purchased power and optimization of resources (e.g., physical and economic dispatch).

There is the potential for continued price volatility in the Company's service territory, particularly during peak periods. Too great a dependence on generation from the wholesale market can lead to power price volatilities depending on available power supply and prevailing natural gas prices. The Company faces load obligation uncertainty due to the potential for customer switching. Some counterparties in these areas have significant credit difficulties, representing credit risk to the Company. Finally, the Company's own credit situation can have an impact on its ability to enter into transactions.

In response to these energy supply challenges, the Company has adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines to procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation. The second element is an energy risk management and risk control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control; and ensures clear distinction between policy setting (or planning) and execution. Lastly, the Company will pursue a process of ongoing regulatory involvement and acknowledgment of the resource portfolio management plans.

Within the energy supply planning process, there are three key components covering different time frames:

- The PUCN-approved long-term integrated resource plan which is filed every three years and has a twenty-year planning horizon;
- The PUCN-approved energy supply plan which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio strategies within which intermediate term resource requirements will be met and has a one to three year planning horizon; and
- Tactical execution activities with a one-month to twelve-month focus.

The energy supply plan operates in conjunction with the PUCN-approved 20-year integrated resource plan. It serves as a guide for near-term execution and fulfillment of energy needs. When the energy supply plan calls for executing contracts of longer than three years, PUCN approval is required.

Energy Efficiency Programs

The Company provides a comprehensive set of energy efficiency and conservation programs to its Nevada electric customers. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Company offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Energy efficiency program costs are recovered through base rates set by the PUCN, and adjusted based on the Company's annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2013, $5 million was expended on the Company's energy efficiency programs resulting in an estimated 37,696 MWh of electric energy savings and an estimated 5 MW of electric peak load management.

Regulated Natural Gas Operations

The Company is engaged in the procurement and distribution of natural gas for customers in its service territory. The Company purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the natural gas from the production areas to the Company's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. The Company sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2013, 11% of the total natural gas delivered through the Company's distribution system was for transportation service.

Customers

The percentages of natural gas sold to retail and wholesale customers by class of customer, total Dth of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2013	2012	2011
Residential	49%	47%	41%
Commercial(1)	23	23	20
Industrial(1)	8	8	7
Total retail	80	78	68
Wholesale	20	22	32
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	19,957	18,058	23,529
Total Dth of transportation service (in thousands)	2,281	2,198	2,236
Total average number of retail customers (in thousands)	154,802	152,903	151,973

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers that use natural gas principally for heating. Industrial customers are non-residential customers that use natural gas principally for their manufacturing processes.

There are seasonal variations in the Company's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of the Company's regulated natural gas revenue is reported in the months of January, February, March and December.

On December 9, 2013, the Company recorded its all-time highest peak-day delivery, as well as its 2013/2014 winter heating season peak day delivery, through its distribution system of 163,574 Dth. This peak-day delivery consisted of 93% traditional retail sales service and 7% transportation service.

Fuel Supply and Capacity

The purchase of natural gas for the Company's regulated natural gas operations is done in combination with the purchase of natural gas for the Company's regulated electric operations. In response to energy supply challenges, the Company has adopted an approach to managing the energy supply function that has three primary elements, as discussed earlier under Generating Facilities and Fuel Supply. Similar to the Company's regulated electric operations, as long as the Company's purchases of natural gas are deemed prudent by the PUCN, through its annual prudency review, the Company is permitted to recover the cost of natural gas. The Company also has the ability to reset quarterly base tariff rates based on the last twelve months fuel costs and to reset quarterly deferred energy adjustments.

Natural gas property consists principally of natural gas mains and services lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of the Company included 3,200 miles of natural gas mains and service lines as of December 31, 2013.

General Regulation

The Company is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and, ultimately, its ability to recover costs. In addition to the following discussion, refer to "Regulatory Matters" in Item 7 of this Form 10-K.

The Company is subject to comprehensive regulation by various federal, state and local agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, the PUCN has established retail electric and natural gas rates on a cost-of-service basis, which are designed to allow the Company an opportunity to recover what the PUCN deems to be the Company's reasonable costs of providing services, including a fair opportunity to earn a reasonable return on its investments based on its cost of debt and equity. In addition to return on investment, the Company's cost of service generally reflects a representative level of prudent expenses, including cost of sales, operating expense, depreciation and amortization, and income and other tax expense, reduced by wholesale electricity and other revenue. The allowed operating expenses are typically based on actual historical costs adjusted for known and measurable or forecasted changes. The PUCN may, as a result of a statutorily mandated general rate proceeding, adjust rates for various reasons, including pursuant to a review of: (a) the Company's revenue and expenses during a defined test period and (b) the Company's level of investment. The PUCN typically has the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, utility customers or organizations representing groups of customers.

The Company's retail electric rates are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. The Company has established energy cost adjustment mechanisms and other cost recovery mechanisms, which helps mitigate its exposure to changes in costs from those assumed in establishing base rates.

The Company generally has an exclusive right to serve retail customers within its service territory, and in turn, has an obligation to provide service to those customers. In Nevada, state law allows retail electric customers with an average annual load of one MW or more to file a letter of intent and application with the PUCN to acquire electric energy and ancillary services from another energy supplier. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN to meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to the Company, the departure must not burden the Company with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances. Currently, there are no material applications pending with the PUCN in the Company's service territory.

Nevada statutes require the Company to file electric general rate cases at least once every three years with the PUCN. The Company is also required to file annual deferred energy accounting adjustment applications to review fuel and purchased power costs for prudency and reasonableness, and if any costs are disallowed on such grounds, the disallowances will be incorporated into the next subsequent quarterly rate change. The Company also makes quarterly filings to reset base tariff energy rates based on the last 12 months fuel and purchased power costs. Additionally, Nevada regulations allow an electric utility that adjusts its base tariff energy rates on a quarterly basis to request approval of the PUCN to make quarterly changes to its deferred energy accounting adjustment rate if the request is in the public interest. The Company filed such an application, which was approved by the PUCN; accordingly, the Company now files quarterly adjustments to the deferred energy accounting adjustment rate. The Company also files annually for the recovery of lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN as well as the implementation costs of energy efficiency programs.

Joint Application of the Company and Nevada Power

In May 2013, the Company and Nevada Power filed a joint application with the PUCN to consolidate the companies into a single jurisdictional utility. On March 14, 2014, the Company and Nevada Power filed a motion with the PUCN to withdraw the joint application to consolidate the Company and Nevada Power into a single jurisdictional utility. The Company and Nevada Power are presently joint dispatching generation facilities pursuant to an interim joint dispatch agreement approved by FERC. The Company and Nevada Power will seek FERC approval for permission to continue to operate an interim joint dispatch agreement through at least 2015.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting and records retention; securities issuances; and other matters. The FERC also has the enforcement authority to assess civil penalties of up to $1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. The Company has implemented programs and procedures that facilitate and monitor compliance with the FERC's regulations described below.

Wholesale Electricity and Capacity

The FERC regulates the Company's rates charged to wholesale customers for electricity and transmission capacity and related services. Most of the Company's wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility.

The Company's authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. During such reviews, the Company must demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in its market area. The Company's most recent triennial filing was made in 2013. Under the FERC's market-based rules, the Company must also file with the FERC a notice of change in status when there is a change in the conditions that the FERC relied upon in granting market-based rate authority.

Transmission

The Company's wholesale transmission services are regulated by the FERC under cost-based regulation subject to the Company's open access transmission tariff. These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. The Company's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. The Company has made several required compliance filings in accordance with these rules.

FERC Reliability Standards

The FERC has established an extensive number of mandatory reliability standards developed by the NERC and the WECC, including planning and operation, critical infrastructure protection and regional standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC, the NERC and the WECC.

Environmental Laws and Regulations

The Company is subject to federal, state and local laws and regulations regarding air and water quality, RPS, 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. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for the Company's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

We are subject to certain risks and uncertainties in our business operations, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by us, should be made before making an investment decision. Additional risks and uncertainties not presently known or which we currently deem immaterial may also impair our business operations.

We are subject to operating uncertainties and events beyond our control that impact the costs to operate, maintain, repair and replace utility systems, which could adversely affect our consolidated financial results.

The operation of complex utility systems that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of our thermal and other electricity generating facilities and related equipment, transmission and distribution lines or other equipment or processes, which could lead to catastrophic events; unscheduled outages; strikes, lockouts or other labor-related actions; shortages of qualified labor; transmission and distribution system constraints; terrorist activities or military or other actions, including cyberattacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, earthquakes, explosions, landslides, wars, terrorism and embargoes. A catastrophic event might result in injury or loss of life, extensive property damage or environmental or natural resource damages. Any of these events or other operational events could significantly reduce or eliminate our revenue or significantly increase our expenses. For example, if we cannot operate our electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event, our revenue could decrease and our expenses could increase due to the need to obtain energy from more expensive sources. Further, we self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. The scope, cost and availability of our insurance coverage may change, including the portion that is self-insured. Any reduction of our revenue or increase in our expenses resulting from the risks described above, could adversely affect our consolidated financial results.

We are subject to extensive federal, state and local legislation and regulation, including numerous environmental, health, safety, reliability and other laws and regulations that affect our operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations are continually being proposed and enacted that impose new or revised requirements or standards on our business.

We are required to comply with numerous federal, state and local laws and regulations as described in Item 1 of this Form 10-K that have broad application to our business and limit our ability to independently make and implement management decisions regarding, among other items, constructing, acquiring or disposing of operating assets; acquiring businesses; operating and maintaining generating facilities and transmission and distribution system assets; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transacting with affiliates; and paying dividends or similar distributions. These laws and regulations are followed in developing our safety and compliance programs and procedures and are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the Occupational Safety and Health Administration, the FERC, the EPA, and the PUCN.

Compliance with applicable laws and regulations generally requires us to obtain and comply with a wide variety of licenses, permits, inspections, audits and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs, damages arising out of contaminated properties and refunds, fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, we could be required to shut down some facilities or materially alter their operations. Further, we may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for our operating assets or development projects. Delays in, or active opposition by third parties to, obtaining any required environmental or regulatory authorizations or failure to comply with the terms and conditions of the authorizations may increase costs or prevent or delay us from operating our facilities, developing or favorably locating new facilities or expanding existing facilities. If we fail to comply with any environmental or other regulatory requirements, we may be subject to penalties and fines or other sanctions, including changes to the way our electricity generating facilities are operated that may adversely impact generation. The costs of complying with laws and regulations could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require us to increase our purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect our consolidated financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition within our service territory; new environmental requirements, including the implementation of RPS and GHG emissions reduction goals; regulations governing the management and disposal of coal combustion byproducts, or the protection of flora or fauna; the implementation of energy efficiency mandates; changes in forecasting requirements; changes to our service territory as a result of condemnation or takeover by municipalities or other governmental entities, particularly where we lack the exclusive right to serve our customers; or a negative impact on our ability to recover costs. In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted from time to time that impose additional or new requirements or standards on our business.

Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. We cannot accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions nor can we determine their impact on us at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs or restrict or otherwise cause an adverse change in how we operate our business. To the extent that we are not allowed by our regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the costs of complying with such additional requirements could have a material adverse effect on our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on our consolidated financial results.

Recovery of our costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect our consolidated financial results.

State Rate Proceedings

Rates are established for our regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but generally have the common objective of limiting rate increases while also requiring us to ensure system reliability. Decisions are subject to judicial appeal, potentially leading to further uncertainty associated with the approval proceedings.

Retail rates in Nevada are based in part upon the state regulatory commission's determination of total utility costs. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs recovered through rates and from time-to-time may result in a state regulator requiring refunds to customers. Furthermore, the state regulatory commission generally sets rates based on a test year established in accordance with the commission's policies. The test year data adopted may create a lag between the incurrence of a cost and its recovery in rates. The state regulatory commission also decides the allowed levels of expense, investment and capital structure that it deems are just and reasonable in providing the service and may disallow recovery in rates for any costs that it believes do not meet such standard. Finally, the state regulatory commission establishes the allowed rate of return we will be given an opportunity to earn on our sources of capital. While rate regulation is premised on providing a fair opportunity to earn a reasonable rate of return on invested capital, the state regulatory commission does not guarantee that we will be able to realize a reasonable rate of return.

FERC Jurisdiction

The FERC authorizes cost-based rates associated with transmission services provided by our transmission facilities. Under the Federal Power Act, we may voluntarily file, or may be obligated to file, for changes, including general rate changes, to our system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which we sell electricity at wholesale and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict our ability to sell electricity at market-based rates, which could adversely affect our consolidated financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

The NERC has standards in place to ensure the reliability of the electric transmission grid and generation system. We are subject to the NERC's regulations and periodic audits to ensure compliance with those regulations. The NERC may carry out enforcement actions for non-compliance and administer significant financial penalties, subject to the FERC's review.

We are actively pursuing, developing and constructing new or expanded facilities, the completion and expected costs of which are subject to significant risk, and we have significant funding needs related to our planned capital expenditures.

We actively pursue, develop and construct new or expanded facilities. We expect that we will incur substantial annual capital expenditures over the next several years. Such expenditures include and may include in the future, among others, construction and other costs for new electricity generating facilities, transmission or distribution projects, environmental control and compliance systems and continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor, siting and permitting and changes in environmental and operational compliance matters, load forecasts and other items over a multi-year construction period, as well as counterparty risk and the economic viability of our suppliers, customers and contractors. Certain of our construction projects are substantially dependent upon a single contractor and replacement of such contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in-service. Such costs may not be recoverable in the rates we are able to charge our customers. It is also possible that additional generation needs may be obtained through power purchase agreements, which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or recover any such costs could adversely affect our consolidated financial results.

Furthermore, we depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we are unable to obtain funding from internal and external sources, we may need to postpone or cancel planned capital expenditures.

A significant sustained decrease in demand for electricity or natural gas in the markets served by us would significantly decrease our operating revenue and could adversely affect our consolidated financial results.

A significant sustained decrease in demand for electricity or natural gas in the markets served by us would significantly reduce our operating revenue and could adversely affect our consolidated financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity or natural gas;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed through various conservation, energy efficiency and distributed generation measures and programs;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels;
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise; and
- sustained mild weather that reduces heating or cooling needs.

Our operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In the markets in which we operate, demand for electricity peaks during the hot summer months when cooling needs are higher. Market prices for electricity also generally peak at that time. In addition, demand for natural gas and other fuels generally peaks during the winter when heating needs are higher. This is especially true in our retail natural gas business. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced.

As a result, our overall consolidated financial results may fluctuate substantially on a seasonal and quarterly basis. We have historically provided less energy, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide energy and could adversely affect our consolidated financial results. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our regulatory environment and contractual agreements, including our ability to recover energy costs and terms of our wholesale sale contracts.

We are subject to market risk associated with the wholesale energy markets, which could adversely affect our consolidated financial results.

In general, our primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, demand for electricity, economic growth and changes in technology. Volumetric changes are caused by fluctuations in generation or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, we purchase electricity and fuel in the open market as part of our normal operating business. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, we may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when we are a net seller of electricity in the wholesale market, we will earn less revenue. Although we have certain energy cost adjustment mechanisms under applicable law, the risks associated with changes in market prices may not be fully mitigated.

A downgrade in our credit ratings could negatively affect our access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

Our long-term debt is rated investment grade by various rating agencies. We cannot assure that our long-term debt will continue to be rated investment grade in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market could be significantly limited, resulting in higher interest costs.

Most of our large wholesale customers, suppliers and counterparties require us to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If our credit ratings were to decline, especially below investment grade, financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other form of security for existing transactions and as a condition to entering into future transactions with us. Such amounts may be material and may adversely affect our liquidity and cash flows.

Potential terrorist activities and the impact of military or other actions, including cyberattacks, could adversely affect our consolidated financial results.

The ongoing threat of terrorism and the impact of military or other actions by nations or politically, ethnically, or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject our operations to increased risks. Additionally, the United States government has issued warnings that energy assets, specifically pipeline and electric utility infrastructure, are potential targets for terrorist attacks, including cyberattacks. Cyberattacks could adversely affect our ability to operate our facilities, information technology and business systems, or compromise confidential customer and employee information. Political, economic, social or financial market instability or damage to or interference with our operating assets or the assets of our customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair or other costs, any of which may materially adversely affect us in ways that cannot be predicted at this time. Any of these risks could materially affect our consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism, sustained or significant cyberattacks, or war could also materially adversely affect our ability to raise capital.

We are subject to counterparty credit risk, which could adversely affect our consolidated financial results.

We are subject to counterparty credit risk related to contractual payment obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom we conduct business could impair the ability of these counterparties to meet their payment obligations. We depend on these counterparties to remit payments on a timely basis. We continue to monitor the creditworthiness of our wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if our wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on our consolidated financial results.

We are subject to counterparty performance risk, which could adversely affect our consolidated financial results.

We are subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. We rely on wholesale suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt the delivery of electricity and require us to incur additional expenses to meet customer needs. In addition, when these contracts terminate, we may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

We rely on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require us to find other customers to take the energy at lower prices than the original customers committed to pay. If our wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on our consolidated financial results.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect our consolidated financial results.

Inflation and increases in commodity prices and fuel transportation costs may affect our business by increasing both operating and capital costs. If we are unable to manage cost increases or pass them on to our customers, our consolidated financial results could be adversely affected.

Poor performance of plan and fund investments and other factors impacting NV Energy's pension and other postretirement benefit plans in which we participate could unfavorably impact our consolidated financial results.

Costs of providing NV Energy's defined benefit pension and other postretirement benefit plans depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and NV Energy's required or voluntary contributions made to the plans. Certain of NV Energy's pension and other postretirement benefit plans are in underfunded positions. NV Energy's pension and other postretirement benefit plans have investments in domestic and foreign equity and debt securities and other investments that are subject to loss. Losses from investments could add to the volatility, size and timing of future contributions. Furthermore, the Pension Protection Act of 2006, as amended, may result in more volatility in the amount and timing of future pension contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on our liquidity by reducing available cash.

Disruptions in the financial markets could affect our ability to obtain debt financing, draw upon or renew existing credit facilities, and have other adverse effects on us.

Disruptions in the financial markets could affect our ability to obtain debt financing or to draw upon or renew existing credit facilities, and have other adverse effects on us. Significant dislocations and liquidity disruptions in the United States and global credit markets, such as those that occurred in 2008 and 2009, may materially impact liquidity in the bank and debt capital markets, making financing terms less attractive for borrowers that are able to find financing and, in other cases, may cause certain types of debt financing, or any financing, to be unavailable. Additionally, economic uncertainty in the United States or globally may adversely affect the United States' credit markets and could negatively impact our ability to access funds on favorable terms or at all. If we are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures and our consolidated financial results.

We are involved in a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We are, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which we are involved could result in additional material payments substantially in excess of established reserves or on terms that could require that we change business practices and procedures or divest ownership of assets. Further, litigation could result in the imposition of financial penalties or injunctions and adverse regulatory consequences, any of which could limit our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could have a material adverse effect on our consolidated financial results.

The ownership and operation of power generating facilities and transmission lines on federal or Indian lands could result in uncertainty related to continued leaseholds, easements and rights-of-way, which could have a significant impact on our business.

Certain portions of the Company's generating facilities and transmission lines that carry power from these facilities are located on federal or Indian lands pursuant to leases, easements or rights-of-way that are effective for specified periods. The Company is currently unable to predict the outcome of discussions with the federal government, the appropriate Indian tribes, the tribes' governing bodies, or the United States Bureau of Indian Affairs with respect to future arrangements for these leases, easements and rights-of-way, or grants of additional land rights for future Company projects.

MEHC could exercise control over us in a manner that would benefit MEHC to the detriment of our creditors.

MEHC, through its subsidiary, owns all of our common stock and has control over all decisions requiring shareholder approval, including the election of our directors. In circumstances involving a conflict of interest between MEHC and our creditors, MEHC could exercise its control in a manner that would benefit MEHC to the detriment of our creditors.

Potential changes in accounting standards may impact our consolidated financial results and disclosures in the future, which may change the way analysts measure our business or financial performance.

The Financial Accounting Standards Board ("FASB") and the SEC continuously make changes to accounting standards and disclosure and other financial reporting requirements. New or revised accounting standards and requirements issued by the FASB or the SEC or new accounting orders issued by the FERC could significantly impact our consolidated financial results and disclosures.

Our business operations and financial results could be adversely affected by our inability to realize, or delay in realizing, anticipated benefits or regulatory commitments relating to the MEHC Merger.

The MEHC Merger may cause an interruption of, or loss of momentum in, the usual activities of our business. The diversion of management's attention, changes in personnel and business methods, and any delays or difficulties encountered in connection with the integration of our operations could adversely affect our business and financial results and could impair our ability to realize the anticipated benefits of the transaction, or to meet regulatory commitments relating to the transaction.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The Company's properties consist of the physical assets necessary to support its electricity and natural gas businesses, which include electric generation, transmission and distribution facilities and natural gas distribution facilities. In addition to these physical assets, the Company has rights-of-way and water rights that enable the Company to utilize its facilities. It is the opinion of the Company's management that the principal depreciable properties owned by the Company are in good operating condition and are well maintained. Substantially all of the Company's property in Nevada is subject to the lien of the Company's General and Refunding Mortgage Indenture filed as an Exhibit to this Form 10-K. For additional information regarding the Company's properties, refer to Item 1 of this Form 10-K and Notes 4 and 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The right to construct and operate the Company's electric transmission and electric and natural gas distribution facilities across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. The Company continues to have the power of eminent domain in Nevada, but it does not have the power of eminent domain with respect to federal or Native American tribal lands.

With respect to real property, each of the electric transmission and electric and natural gas distribution facilities fall into two basic categories: (1) parcels that are owned in fee, such as certain of the Company's electricity generating facilities and substations; and (2) parcels where the interest derives from leases, easements, rights-of-way, permits, franchises or licenses from landowners or governmental authorities, or from prescription, permitting the use of such land for the construction, operation and maintenance of the electric generation and transmission and electric and natural gas distribution facilities. The Company believes that it has satisfactory title to all of the real property making up its respective facilities in all material respects.

Item 3. Legal Proceedings

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 consolidated 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. Refer to Note 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding legal proceedings.

Item 4. Mine Safety Disclosures

None.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

All of the Company's common stock is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of MEHC.

In 2013 and 2012, the Company declared and paid dividends of $77 million and $20 million, respectively, to NV Energy.

Item 6. Selected Financial Data

The following tables set forth the Company's selected consolidated historical financial data, which should be read in conjunction with the information in Item 7 of this Form 10-K and with the Company's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected historical consolidated financial data has been derived from the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2013	2012	2011	2010	2009
Consolidated Statement of Operations Data:					
Regulated electric operating revenue	$ 747	$ 726	$ 716	$ 837	$ 957
Regulated natural gas operating revenue	106	108	173	191	205
Operating income	140	188	171	181	171
Net income	55	84	60	72	73

	As of December 31,				
	2013	2012	2011	2010	2009
Consolidated Balance Sheet Data:					
Total assets	$ 3,369	$ 3,316	$ 3,216	$ 3,378	$ 3,371
Long-term debt, including current maturities	1,200	1,179	1,179	1,196	1,297
Shareholder's equity	1,016	1,039	975	973	1,009

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

General

The Company's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy and resources. The Company is a summer peaking utility experiencing its highest retail energy sales in response to the demand for air conditioning. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of the Company. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of the Company.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

Results of Operations

The Company earned net income of $55 million for 2013, a decrease of $29 million, or 35% compared to 2012 and earned net income of $84 million in 2012, an increase of $24 million, or 40% compared to 2011.

The Company believes presenting gross margin allows the reader to assess the impact of the Company's regulatory treatment and its overall regulatory environment on a consistent basis and is meaningful. Gross margin, as a percentage of revenue, is primarily impacted by the fluctuations in electric and natural gas supply costs versus the fixed rates collected from customers. While these fluctuating costs impact gross margin as a percentage of revenue, they only impact gross margin amounts if the costs cannot be passed through to customers.

Regulated Electric Gross Margin

A comparison of key results related to regulated electric gross margin for the years ended December 31 is as follows:

	2013	2012	Change		2012	2011	Change	
Gross margin (in millions):								
Operating electric revenue	$ 747	$ 726	$ 21	3%	$ 726	$ 716	$ 10	1 %
Cost of fuel, energy and capacity	292	263	29	11	263	273	(10)	(4)
Gross margin	$ 455	$ 463	$ (8)	(2)	$ 463	$ 443	$ 20	5
Sales (GWh):								
Residential	2,370	2,284	86	4%	2,284	2,231	53	2 %
Commercial	2,948	2,930	18	1	2,930	2,852	78	3
Industrial	2,818	2,707	111	4	2,707	2,565	142	6
Total retail	8,136	7,921	215	3	7,921	7,648	273	4
Wholesale	891	1,025	(134)	(13)	1,025	920	105	11
Total sales	9,027	8,946	81	1	8,946	8,568	378	4
Average number of retail customers (in thousands)	327	324	3	1%	324	322	2	1 %
Average retail revenue per MWh:	$ 83.70	$ 83.32	$ 0.38	—%	$ 83.32	$ 84.72	$ (1.40)	(2)%
Heating degree days	5,008	4,352	656	15%	4,352	5,112	(760)	(15)%
Cooling degree days	1,177	1,272	(95)	(7)	1,272	964	308	32
Sources of energy (GWh):								
Coal	1,430	1,025	405	40%	1,025	1,199	(174)	(15)%
Natural gas	3,712	3,997	(285)	(7)	3,997	3,255	742	23
Total energy generated	5,142	5,022	120	2	5,022	4,454	568	13
Energy purchased	4,157	4,055	102	3	4,055	4,368	(313)	(7)
Total	9,299	9,077	222	2	9,077	8,822	255	3

Regulated Natural Gas Gross Margin

A comparison of key results related to regulated natural gas gross margin for the years ended December 31 is as follows:

	2013	2012	Change		2012	2011	Change	
Gross margin (in millions):								
Operating natural gas revenue	$ 106	$ 108	$ (2)	(2)%	$ 108	$ 173	$ (65)	(38)%
Natural gas purchased for resale	56	62	(6)	(10)	62	124	(62)	(50)
Gross margin	$ 50	$ 46	$ 4	9	$ 46	$ 49	$ (3)	(6)
Sales (Dth):								
Residential	9,791	8,525	1,266	15 %	8,525	9,585	(1,060)	(11)%
Commercial	4,604	4,198	406	10	4,198	4,654	(456)	(10)
Industrial	1,488	1,322	166	13	1,322	1,542	(220)	(14)
Total retail	15,883	14,045	1,838	13	14,045	15,781	(1,736)	(11)
Average number of retail customers (in thousands)	155	153	2	1 %	153	152	1	1 %
Average revenue per retail Dth sold:	$ 6.48	$ 6.71	$ (0.23)	(3)%	$ 6.71	$ 8.85	$ (2.14)	(24)%
Average cost of natural gas per retail Dth sold	$ 4.53	$ 4.41	0.12	3 %	$ 4.41	$ 7.79	$ (3.38)	(43)%
Heating degree days	5,008	4,352	656	15 %	4,352	5,112	(760)	(15)%

Year ended December 31, 2013 compared to year ended December 31, 2012

Regulated electric gross margin decreased $8 million, or 2% for the year ended December 31, 2013 compared to 2012 primarily due to:

- a decrease in energy efficiency program rate revenues of $8 million, offset in operating and maintenance expense;
- a one-time bill credit to retail customers totaling $5 million in connection with the MEHC Merger; and
- a decrease of $5 million in energy efficiency implementation revenue.

The decrease in regulated electric gross margin was partially offset by:

- an increase in net usage of $7 million;
- an increase in transmission revenue of $1 million; and
- a slight increase in growth of $1 million.

Regulated natural gas gross margin increased $4 million, or 9% for the year ended December 31, 2013 compared to 2012 primarily due to an increase in customer usage from colder weather.

Operating and maintenance expense increased $7 million, or 4% for 2013 compared to 2012 primarily due to:

- a disallowance in 2013 of $5 million of energy efficiency implementation revenue previously recorded in 2012;
- an impairment charge in 2013 of $4 million related to the recovery of certain assets not currently in rates;
- disallowances related to the Company's general rate case of $6 million;
- increased regulatory expense of $3 million; and
- canceled projects of $1 million.

The increase in operating and maintenance expense was partially offset by:

- decreased energy efficiency program costs of $8 million, which are fully recovered in operating revenue and
- decreased maintenance expense at the Tracy and Clark Mountain Generating Stations and other general maintenance totaling $4 million.

Depreciation and amortization increased $15 million, or 14% for the year ended December 31, 2013 compared to 2012 primarily as a result of establishment of regulatory liabilities related to the Company's general rate case of $11 million and higher plant-in-service and software amortizations.

Property and other taxes increased $2 million, or 1% for the year ended December 31, 2013 compared to 2012 primarily due to an increase in property taxes rates.

The Company incurred costs totaling $20 million in 2013 related to the MEHC Merger, consisting of amounts payable under NV Energy's change in control policy of $6 million, accelerated vesting and stock compensation under NV Energy's long-term incentive plan of $7 million, investment banker fees of $6 million and legal and other expenses of $1 million.

Interest expense decreased $3 million, or 5% for the year ended December 31, 2013, compared to 2012 primarily due to decreased debt amortization expense and financing activities.

Income tax expense decreased $7 million, or 18% for the year ended December 31, 2013 compared to 2012 due to lower income before income tax expense and an increase in the effective tax rate. The effective tax rate was 37% and 32%, for the year ended December 31, 2013 and 2012, respectively. The increase in the effective tax rate is due to the effects of ratemaking of 2%, adjustments due to finalization of the tax audit in 2012 of 2% and certain non-deductible merger related costs of 1%.

Year ended December 31, 2012 compared to year ended December 31, 2011

Regulated electric gross margin increased $20 million, or 5% for the year ended December 31, 2012, compared to 2011, primarily due to:

- the implementation of energy efficiency program rate revenue, effective July 1, 2011 and energy efficiency program rate revenue amortization, effective October 1, 2011 of $9 million offset in operating and maintenance;
- an increase in net usage of $4 million;
- an increase in customer growth of $4 million; and
- an increase in energy efficiency implementation rate revenue of $2 million.

Regulated natural gas gross margin decreased $3 million, or 6% for the year ended December 31, 2012 compared to 2011 primarily due to a decrease in customer usage from warmer weather.

Operating and maintenance expense decreased $2 million, or 1% for 2012 compared to 2011 primarily due to:

- a decrease in planned maintenance and outages at the Valmy Generating Station of $6 million;
- a decrease in pension and benefit costs of $4 million; and
- an increase in capitalization of costs due to increased construction activity of $3 million.

The decrease in operating and maintenance expense was partially offset by:

- increased energy efficiency program costs of $9 million, which are fully recovered in operating revenue and
- an increase in legal fees of $2 million.

Depreciation and amortization increased $2 million, or 2% for the year ended December 31, 2012, compared to 2011, primarily due to increased plant-in-service.

Interest expense decreased $4 million, or 6% for the year ended December 31, 2012, compared to 2011 primarily due to a decrease in debt amortization expense.

Income tax expense increased $9 million, or 29% for the year ended December 31, 2012 compared to 2011 due to higher income before income tax expense offset by a decrease in the effective tax rate. The effective tax rate was 32% and 34%, for the year ended December 31, 2012 and 2011, respectively. The decrease in the effective tax rate is due to the effects of ratemaking and adjustments due to finalization of the tax audit in 2012.

Liquidity and Capital Resources

As of December 31, 2013, the Company's total net liquidity was $311 million consisting of $67 million in cash and cash equivalents and $244 million of revolving credit facility availability.

Operating Activities

The Company's net cash flows from operating activities for the years ended December 31, 2013 and 2012 were $226 million and $197 million, respectively. The change in cash from operations was primarily due to a decrease in the deferred energy refund to customers, reduced spend on renewable energy programs, reduced coal purchases, receipt of insurance proceeds, timing of payments and accruals and increased collection of energy efficiency implementation rate revenue, partially offset by an under-collection of energy costs as result of adjustments to base tariff energy rates and higher fuel costs and timing of customer collections.

The Company's net cash flows from operating activities for the years ended December 31, 2012 and 2011 were $197 million and $176 million, respectively. The change in cash from operations was primarily due to over-collection of deferred energy costs, reduced spend on renewable energy programs and over-collection of energy efficiency program rate revenues, partially offset by the timing of payments and accruals.

Investing Activities

The Company's net cash flows from investing activities for the years ended December 31, 2013 and 2012 were $(139) million and $(169) million, respectively. The change was primarily due to reduced capital expenditures for the NV Energize project, partially offset by a reduction in contributions in aid of construction received for the NV Energize project under the American Recovery and Reinvestment Act of 2009.

The Company's net cash flows from investing activities for the years ended December 31, 2012 and 2011 were $(169) million and $- million, respectively. The change from 2011 is primarily due to capital expenditures for the NV Energize project in 2012, proceeds received in 2011 for the sale of the Company's electric and distribution assets in California, partially offset by contributions in aid of construction received for the NV Energize project under the American Recovery and Reinvestment Act of 2009.

Financing Activities

The Company's net cash flows from financing activities for the years ended December 31, 2013 and 2012 were $(81) million and $(22) million, respectively. The change was primarily due to an increase in dividends paid to NV Energy. In August 2013, the Company issued and sold $250 million of its 3.375% Series T General and Refunding Securities, due 2023. In September 2013, the Company paid at maturity the $250 million principal amount of its 5.45% Series Q General and Refunding Securities.

The Company's net cash flows from financing activities for the years ended December 31, 2012 and 2011 were $(22) million and $(131) million, respectively. The change was primarily due to a reduction in dividends paid to NV Energy.

Ability to Issue Debt

The Company's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2013, the Company has financing authority from the PUCN consisting of authority to: (1) issue additional long-term debt securities of up to $350 million; (2) refinance up to $348 million of long-term debt securities; and (3) maintain a revolving credit facility of up to $600 million. The Company's revolving credit facility contains a financial maintenance covenant which the Company was in compliance with as of December 31, 2013. In addition, certain financing agreements contain covenants which are currently suspended as the Company's senior secured debt is rated investment grade. However, if the Company's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, the Company would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent the Company has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, the Company's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under the Company's indenture.

The Company's indenture creates a lien on substantially all of the Company's properties in Nevada. As of December 31, 2013, $1.5 billion of the Company's assets were pledged. The Company had the capacity to issue $882 million of additional general and refunding mortgage securities as of December 31, 2013 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. The Company also has the ability to release property from the lien of the Company's indenture on the basis of net property additions, cash or retired bonds. To the extent the Company releases property from the lien of the Company's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in environmental and other rules and regulations; impacts to customers' rates; outcomes of regulatory proceedings; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; commodity prices; and the cost and availability of capital. Prudently incurred expenditures for compliance-related items such as pollution control technologies, replacement generation and associated operating costs are generally incorporated into the Company's regulated retail rates. Expenditures for certain assets may ultimately be through acquisition.

The Company estimates that it will spend approximately $659 million on capital projects over the next three years, excluding non-cash equity AFUDC and other non-cash items.

Forecasted capital expenditures, which exclude non-cash equity AFUDC and other non-cash items, for the years ending December 31 are as follows (in millions):

	2014	2015	2016
Generation development	$ 65	$ 33	$ 22
Distribution	113	125	113
Transmission system investment	18	38	36
Other	46	28	22
Total	$ 242	$ 224	$ 193

Contractual Obligations

The Company has contractual cash obligations that may affect its financial condition. The following table summarizes the material contractual cash obligations of the Company as of December 31, 2013 (in millions):

	Payments Due By Periods				
	2014	2015-2016	2017-2018	2019 and After	Total
Long-term debt maturities	$ —	$ 450	$ —	$ 716	$ 1,166
Long-term debt interest payments	53	94	53	381	581
Purchased power	94	194	177	585	1,050
Purchased power - not commercially operable(1)	—	7	14	146	167
Coal and natural gas	154	59	—	—	213
Transportation	78	88	59	108	333
Long-term service agreements(2)	5	9	8	11	33
Capital projects	—	6	6	48	60
Operating leases	4	6	3	34	47
Capital leases	3	5	5	46	59
Total contractual cash obligations	$ 391	$ 918	$ 325	$ 2,075	$ 3,709

(1) Represents 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 energy.

(2) Amounts based on estimated usage.

Regulatory Matters

The Company is subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding the Company's general regulatory framework.

In June 2013, the Company filed its statutorily required triennial general rate case for its Nevada electric operations and updated the filing in August 2013. The filing, as updated, requested a return on equity of 10.40% and a decrease in general rates of $5 million. The PUCN issued its order in December 2013 granting a return on equity of 9.80% and a $37 million general rate decrease, which was effective January 1, 2014. As a result of the final order the Company recorded $2 million of operating and maintenance expense in the Consolidated Statements of Operations related to general study costs originally deferred.

In June 2013, the Company filed a general rate case for its natural gas operations and updated the filing in August 2013. The filing, as updated, requested a return on equity of 10.35% and an increase in general rates of $6 million. The PUCN issued its order in December 2013 granting a return on equity of 9.7% and a $4 million increase to general rates which was effective January 1, 2014.

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, pre-tax, in EEIR revenue (including carrying charges) and the Company recorded a charge to operating and maintenance expense on the Consolidated Statements of Operations 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 Consolidated Balance Sheets. On February 28, 2014, the Company filed an application with the PUCN to reset the EEIR and the 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.

Environmental Laws and Regulations

The Company is subject to federal, state and local laws and regulations regarding air and water quality, RPS, 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. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various state and local agencies. The Company believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts.

Clean Air Act Regulations

The Clean Air Act is a federal law administered by the EPA that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in SIPs, which are a collection of regulations, programs and policies to be followed. SIPs vary by state and are subject to public hearings and EPA approval. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs most directly affecting the Company's operations are described below.

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxides, particulate matter, ozone and sulfur dioxide, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present.

In January 2010, the EPA proposed a rule to strengthen the national ambient air quality standard for ground level ozone. The proposed rule arose out of legal challenges claiming that a March 2008 rule that reduced the standard from 80 parts per billion to 75 parts per billion was not strict enough. The new rule proposed a standard between 60 and 70 parts per billion. In September 2011, the President requested that the EPA withdraw the proposed ozone standard and allow the review of the standards to proceed through the regularly scheduled review in 2013; such action, however, was not undertaken in 2013. In litigation pending in the United States District Court for the Northern District of California after the EPA missed its March 2013 deadline for completing its standards review, the plaintiffs have requested the court to require the EPA to issue final standards for ozone by October 2015.

The EPA has indicated it anticipates proposing ozone standards in 2014. Until the standards are reviewed or revised, the EPA is proceeding with implementation of the March 2008 ozone standards and, in December 2011, issued its response to states' recommendations on area attainment designations.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 100 parts per billion. In February 2012, the EPA published final designations indicating that based on air quality monitoring data, all areas of the country are designated as "unclassifiable/attainment" for the 2010 nitrogen dioxide national ambient air quality standard.

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide. Under the new rule, the existing 24-hour and annual standards for sulfur dioxide, which were 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year, were replaced with a new one-hour standard of 75 parts per billion. The new rule utilizes a three-year average to determine attainment. The rule utilizes source modeling in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas. Attainment designations were due by June 2012; however, citing a lack of sufficient information to make the designations, the EPA did not issue its final designations until July 2013. Although the EPA's July 2013 designations did not impact the Company's generating facilities, the EPA's assessment of sulfur dioxide area designations will continue with the deployment of additional sulfur dioxide monitoring networks across the country.

In June 2012, the EPA released a proposal to strengthen the fine particulate matter national ambient air quality standards, reducing the standard from 15 micrograms per cubic meter to a range of 12 to 13 micrograms per cubic meter while taking comment on a standard of 11 micrograms per cubic meter. The EPA also proposed a new, separate fine particulate matter standard of either 28 or 30 deciviews, aimed at improving visibility. The new standard was released in December 2012, setting 12 micrograms per cubic meter as the annual standard and retaining the 24-hour standard at 35 micrograms per cubic meter. The EPA did not set a separate secondary visibility standard, choosing to rely on the existing secondary 24-hour standard to protect against visibility impairment. The EPA anticipates making initial attainment designations by December 2014 that are likely to become effective in early 2015. States would have until 2020 to meet the revised annual standard. Until the attainment designations are made, the Company cannot determine the potential impacts of the standards; however, with the release of the final standards, the EPA indicated its projections show 99% of all counties in the United States with monitors would meet the revised standard. As a result, the Company does not anticipate that any impacts of the revised standard will be significant.

As new, more stringent standards are adopted, the number of counties designated as nonattainment areas is likely to increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until additional monitoring and modeling is conducted, the impacts on the Company cannot be determined.

Mercury and Air Toxics Standards

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fueled generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. In March 2011, the EPA proposed a new rule that would require coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards rather than a cap-and-trade system. The final rule, MATS, was published in the Federal Register in February 2012, with an effective date of April 16, 2012, and requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The Company believes that its emissions reduction projects completed to date or currently permitted or planned for installation are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities to comply with the final rule's standards.

Incremental costs to install and maintain emissions control equipment at the Company's coal-fueled generating facilities and any requirement to shut down what have traditionally been low cost coal-fueled generating facilities will likely increase the cost of providing service to customers. In addition, numerous lawsuits are pending against the MATS in the D.C. Circuit, which may have an impact on the Company's compliance obligations and the timing of those obligations. Oral arguments were heard on the MATS in the D.C. Circuit in December 2013, and a decision in the pending cases is expected in 2014.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Certain of the Company's fossil-fueled generating facilities in Nevada are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to best available retrofit technology ("BART") requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

In March 2012, the EPA approved Nevada's SIP implementing the regional haze rules for the Tracy and Ft. Churchill Generation Stations where compliance with the controls and emission limits is required by January 2015. The EPA approved Nevada's determination that installation of selective non-catalytic reduction technology represented BART. The Company has received approval from the PUCN to retire Tracy Generating Station Units 1 and 2 by December 31, 2014 and to install retrofit controls at Tracy Generating Station Unit 3 and Ft. Churchill Generating Station Units 1 and 2 which are expected to be operational by January 1, 2015.

Environmental groups have challenged both of the EPA's final determinations with respect to Nevada's regional haze SIP. Until such time as the lawsuits are concluded, the impact on the Tracy and Ft. Churchill Generating Stations cannot be fully determined; however, an adverse decision could result in the requirement to install more stringent controls or the retirement of certain units earlier than currently planned.

A case was filed in the Tenth Circuit appealing a FIP issued by the EPA in New Mexico. In addition, two cases involving the EPA's issuance of a FIP were appealed to the United States Supreme Court in 2014, one from the Tenth Circuit based on the EPA rejecting portions of the Oklahoma SIP and one from the United States Court of Appeals for the Eighth Circuit based on the EPA's rejection of the North Dakota SIP. It is not yet known whether the United States Supreme Court will hear the Oklahoma or the North Dakota cases.

Until the EPA takes final action in Nevada and decisions have been made on each appeal, the Company cannot fully determine the impacts of the Regional Haze regulation on its generating facilities.

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. In addition to the proposed changes, differing interpretations by the EPA and the courts create risk and uncertainty for entities when seeking permits for new projects and installing emissions controls at existing facilities under NSR requirements. The Company monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various coal-fueled generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting.

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.

Climate Change

While significant measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. Regulation of GHG emissions under various provisions of the Clean Air Act has continued since the EPA's December 2009 findings that GHG emissions threaten public health and welfare.

In May 2010, the EPA issued the GHG "Tailoring Rule" to address permitting requirements for GHG after determining that GHG are subject to regulation and would trigger Clean Air Act permitting requirements for stationary sources beginning in January 2011. Numerous lawsuits have been filed on both the EPA's endangerment finding and the Tailoring Rule in the D.C. Circuit. In June 2012, the D.C. Circuit dismissed the challenges to the rules and upheld the EPA's actions. Petitions for rehearing by the full D.C. Circuit were filed, which were denied in December 2012.

In April 2012, the EPA proposed New Source Performance Standards for GHG at new fossil-fueled generating facilities that would require an emissions rate of 1,000 pounds per MWh. In September 2013, the EPA issued a re-proposal of the New Source Performance Standards for GHG at new fossil-fueled generating facilities that would require natural gas-fueled generating facilities to meet a standard of 1,000 pounds to 1,100 pounds per MWh and coal-fueled generating facilities to meet a standard of 1,100 pounds per MWh on an annual basis. The re-proposed standards were published in the Federal Register in January 2014, and the public comment period has been extended to May 9, 2014. Any new fossil-fueled generating units constructed by the Company will be required to meet the final New Source Performance Standards. The EPA is also under a consent decree to establish GHG emissions performance standards for existing and modified sources. In June 2013, President Obama issued a Climate Action Plan, which requires the EPA to issue proposed guidelines for GHG emissions from existing fossil-fueled generating facilities by June 2014, with final guidelines to be issued by June 2015, and states to submit implementation plans by June 2016. Until the standards or guidelines for existing fossil-fueled generating facilities are proposed and finalized, the impact on the Company's generating facilities cannot be determined.

While the debate continues at the federal and international level over the direction of climate change policy, several states have continued to implement state-specific laws or regional initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing climate change related litigation under existing laws.

In September 2009, the EPA issued its final rule regarding mandatory reporting of GHG ("GHG Reporting") beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. The Company is subject to this requirement.

New federal, regional and state accords, legislation, regulation, or judicial proceedings limiting GHG emissions could have a material adverse impact on the Company and the United States' economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fueled generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emissions control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new requirements may impact the Company include:

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;
- Acquiring and renewing construction and operating permits for new and existing generating facilities may be costly and difficult;
- Additional costs may be incurred to purchase and deploy new generating technologies;
- Costs may be incurred to retire existing coal-fueled generating facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;
- Operating costs may be higher and generating unit outputs may be lower;
- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a business risk; and
- The Company's electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence the Company's existing and future electricity generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

GHG Tailoring Rule

The EPA finalized the GHG "Tailoring Rule" in May 2010 requiring new or modified sources of GHG emissions with increases of 75,000 or more tons per year of total GHG to determine the best available control technology for their GHG emissions beginning in January 2011. New or existing major sources are also subject to Title V operating permit requirements for GHG. Beginning July 1, 2011 through June 30, 2013, new construction projects that emit GHG emissions of at least 100,000 tons per year and modifications of existing facilities that increase GHG emissions by at least 75,000 tons per year will be subject to permitting requirements and facilities that were previously not subject to Title V permitting requirements will be required to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents. The EPA issued a GHG best available control technology guidance document in November 2010 in an effort to provide permitting authorities guidance on how to conduct a best available control technology review for GHG. To date, permitting authorities implementing the GHG Tailoring Rule have included efficiency improvements to demonstrate compliance with best available control technology for GHG, as well as requiring emissions limits for GHGs in permits; as such, the impacts of the Tailoring Rule on the Company have not been material.

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per MWh. In June 2013, President Obama announced a national climate change strategy and issued a presidential memorandum requiring the EPA to issue a re-proposed GHG new source performance standard for fossil-fueled generating facilities by September 2013. Rather than re-propose the April 2012 proposal, the EPA issued a new proposal. The September 2013 GHG new source performance standards released by the EPA set different standards for coal-fueled and natural gas-fueled generating facilities. The proposed standard for natural gas-fueled generating facilities considers the size of the unit and the electricity sent to the grid from the unit, establishing a standard of 1,000 to 1,100 pounds of carbon dioxide per MWh. The standard proposed for coal-fueled generating facilities is 1,100 pounds of carbon dioxide per MWh on an annual basis or 1,000 to 1,050 pounds of carbon dioxide per MWh averaged over a seven-year period, both of which would require partial carbon capture and sequestration. The proposed standards were published in the Federal Register on January 8, 2014, and the 60-day public comment period has been extended to May 9, 2014. Any new fossil-fueled generating facilities constructed by the Company will be required to meet the final GHG new source performance standards.

GHG Litigation

The Company closely monitors ongoing environmental litigation. Numerous lawsuits have been unsuccessfully pursued against the industry that attempt to link GHG emissions to public or private harm. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. These cases have typically been appealed to federal appellate courts and, in certain circumstances, to the United States Supreme Court. While unsuccessful to date, an adverse ruling in such cases would likely result in increased regulation and costs for GHG emitters, including the Company's generating facilities.

Renewable Portfolio Standards

Since 1997, the Company has been required to comply with a RPS. Current law requires the Company to meet 18% of its energy requirements with renewable resources for 2014, 20% for 2015 through 2019, 22% for 2020 and 2024, and 25% for 2025 and thereafter. The RPS also requires 5% of the portfolio requirement come from solar resources through 2015 and increasing to 6% in 2016. Nevada law also permits energy efficiency measures to be used to satisfy a portion of the RPS through 2025, subject to certain limitations. The Company is in compliance with these requirements.

Water Quality Standards

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new technology-based performance standards for existing electricity generating facilities that take in more than 50 million gallons of water per day. These rules were aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion.

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. The Company does not utilize once-through cooling water intake or discharge structures at any of its generating facilities. All of the Company's generating stations are designed to have either minimal or zero discharge; therefore, they are not expected to be impacted by the §316(b) final rule.

In June 2013, the EPA published proposed effluent limitation guidelines and standards for the steam electric power generating sector. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions have changed the effluent discharged from coal- and natural gas-fueled generating facilities. The EPA expects the final rule to be published in May 2014. It is likely that the new guidelines will impose more stringent limits on wastewater discharges from coal-fueled generating facilities and ash and scrubber ponds. However, until the revised guidelines are finalized, the Company cannot predict the impact on its generating facilities.

Coal Combustion Byproduct Disposal

In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the Resource Conservation and Recovery Act ("RCRA"). Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. The public comment period closed in November 2010. The EPA has indicated the rule will be finalized by December 19, 2014; however, at this time, the substance of the final rule is not known. In briefs filed in litigation pending in the D.C. Circuit to force the EPA to meet a deadline to issue final coal combustion byproduct rules, the EPA indicated it needs until at least the end of 2014 to review comments, formulate a risk assessment and coordinate the rule with the effluent limit guidelines. Efforts have continued in the United States Congress to pass legislation precluding the EPA from regulating coal combustion byproducts as a hazardous waste under RCRA Subtitle C; however, to date, none of these efforts have resulted in legislation passing both houses of the United States Congress. Ash products are handled and processed in a dry form at the Valmy Generation Station.

Other

Other laws, regulations and agencies to which the Company is subject include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.

The Company expects to be allowed to recover the prudently incurred costs to comply with the environmental laws and regulations discussed above. The Company's planning efforts take into consideration the complexity of balancing factors such as: (a) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality and protect wildlife; (b) avoidance of excessive reliance on any one generation technology; (c) costs and trade-offs of various resource options including energy efficiency, demand response programs and renewable generation; (d) state-specific energy policies, resource preferences and economic development efforts; (e) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (f) keeping rates as affordable as possible. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places the Company at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, the Company has established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts help reduce costs associated with replacement power and maintain system reliability.

Collateral and Contingent Features

Debt of the Company is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the Company's ability to, in general, meet the obligations of its issued debt. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

The Company has no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In July 2010, the President signed into law the Dodd-Frank Reform Act. The Dodd-Frank Reform Act reshapes financial regulation in the United States by creating new regulators, regulating markets and firms not previously regulated, and providing new enforcement powers to regulators. Virtually all major areas of the Dodd-Frank Reform Act are and have been subject to extensive rulemaking proceedings being conducted both jointly and independently by multiple regulatory agencies, many of which have been completed and others that are expected to be finalized in 2014.

The Company is a party to derivative contracts, including over-the-counter derivative contracts. The Dodd-Frank Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of position limits, mandatory clearing, exchange trading, capital, margin, reporting, recordkeeping and business conduct requirements. Many of these requirements are primarily for "swap dealers" and "major swap participants," but many of these also impose some requirements on all market participants, including the Company. The Dodd-Frank Reform Act provides certain exemptions from many of these requirements for commercial end-users when using derivatives to hedge or mitigate commercial risk of their businesses. The Company qualifies or believes it will qualify for many of these exemptions. The Company generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging or mitigating commercial risk and has determined that it is not a swap dealer or major swap participant. The outcome of pending and remaining Dodd-Frank Reform Act rulemaking proceedings cannot be predicted but requirements resulting from these proceedings could directly impact the Company or could have impacts to energy and other markets in general that could have an impact on the Company's consolidated financial results.

Inflation

Historically, overall inflation and changing prices in the economies where the Company operates has not had a significant impact on the Company's consolidated financial results. The Company operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, the Company is allowed to include prudent costs in its rates, including the impact of inflation. The Company attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by the Company's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with the Company's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

The Company prepares its Consolidated 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").

Impairment of Long-Lived Assets

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. Substantially all property, plant and equipment was used in regulated businesses as of December 31, 2013. For all other assets, any resulting impairment loss is reflected on the Consolidated Statements of Operations.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect the Company's results of operations.

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. 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 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 Consolidated 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 consolidated 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 Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $65 million as of December 31, 2013. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which the Company transacts. The following discussion addresses the significant market risks associated with the Company's business activities. The Company has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's contracts accounted for as derivatives.

Commodity Price Risk

The Company is principally exposed to electricity, natural gas and coal commodity price risk as the Company has an obligation to serve retail customer load in its regulated service territory. The Company's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. The Company does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production, generally at fixed prices. Currently, the Company does not use financial instruments to hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The Company's exposure to commodity price risk is generally limited by its ability to include the costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, the Company's fixed-rate long-term debt does not expose the Company to the risk of loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes in fair value would impact earnings and cash flows only if the Company were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of the Company's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 7 and 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of the Company's short- and long-term debt.

As of December 31, 2013 and 2012, the Company had short- and long-term variable-rate obligations totaling $214 million that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2013 and 2012.

Credit Risk

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

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

As of December 31, 2013, the Company's aggregate credit exposure from energy related transactions was not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Power Company and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
March 31, 2014

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2013	**2012**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 67	$ 61
Accounts receivable, net	156	124
Inventories	43	60
Regulatory assets	15	—
Income taxes receivable	10	10
Deferred income taxes	48	22
Other current assets	13	12
Total current assets	352	289
Property, plant and equipment, net	2,552	2,530
Regulatory assets	427	469
Other assets	38	28
Total assets	$ 3,369	$ 3,316
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 151	$ 128
Accrued interest	15	16
Accrued property, income and other taxes	12	2
Accrued employee expenses	7	14
Regulatory liabilities	37	51
Current portion of long-term debt	1	250
Customer deposits and other	16	14
Total current liabilities	239	475
Long-term debt	1,199	929
Regulatory liabilities	243	226
Deferred income taxes	525	466
Other long-term liabilities	147	181
Total liabilities	2,353	2,277
Commitments and contingencies (Note 15)		
Shareholder's equity:		
Common stock - $3.75 stated value, 20,000,000 shares authorized and 1,000 issued and outstanding as of December 31, 2013 and 2012	—	—
Other paid-in capital	1,111	1,111
Accumulated deficit	(93)	(71)
Accumulated other comprehensive loss, net	(2)	(1)
Total shareholder's equity	1,016	1,039
Total liabilities and shareholder's equity	$ 3,369	$ 3,316

The accompanying notes are an integral part of the consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2013	**2012**	**2011**
Operating revenue:			
Regulated electric	$ 747	$ 726	$ 716
Regulated natural gas	106	108	173
Total operating revenue	853	834	889
Operating costs and expenses:			
Cost of fuel, energy and capacity	292	263	273
Natural gas purchased for resale	56	62	124
Operating and maintenance expense	197	190	192
Depreciation and amortization	123	108	106
Property and other taxes	25	23	23
Merger-related expenses	20	—	—
Total operating costs and expenses	713	646	718
Operating income	140	188	171
Other income (expense):			
Interest expense, net of allowance for debt funds	(60)	(63)	(67)
Allowance for equity funds	2	3	3
Other, net	6	(4)	(16)
Total other income (expense)	(52)	(64)	(80)
Income before income tax expense	88	124	91
Income tax expense	33	40	31
Net income	$ 55	$ 84	$ 60

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
December 31, 2010	1,000	$ —	$ 1,111	$ (135)	$ (3)	$ 973
Net income	—	—	—	60	—	60
Dividends declared	—	—	—	(60)	—	(60)
Other	—	—	—	—	2	2
December 31, 2011	1,000	—	1,111	(135)	(1)	975
Net income	—	—	—	84	—	84
Dividends declared	—	—	—	(20)	—	(20)
December 31, 2012	1,000	—	1,111	(71)	(1)	1,039
Net income	—	—	—	55	—	55
Dividends declared	—	—	—	(77)	—	(77)
Other	—	—	—	—	(1)	(1)
December 31, 2013	1,000	$ —	$ 1,111	$ (93)	$ (2)	$ 1,016

The accompanying notes are an integral part of these consolidated financial statements.

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31, 2013	2012	2011
Cash flows from operating activities:			
Net income	$ 55	$ 84	$ 60
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	123	108	106
Deferred income taxes and amortization of investment tax credits	36	48	31
Allowance for equity funds	(2)	(3)	(3)
Amortization of deferred energy	(43)	(108)	(127)
Deferred energy	(24)	73	68
Amortization of other regulatory assets	77	75	82
Other, net	20	(2)	9
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	(17)	(43)	(47)
Inventories	17	(4)	(9)
Accounts payable and other liabilities	(16)	(31)	6
Net cash flows from operating activities	226	197	176
Cash flows from investing activities:			
Capital expenditures	(157)	(211)	(146)
Contributions in aid of construction and customer advances	18	42	11
Proceeds from sale of assets	—	—	135
Net cash flows from investing activities	(139)	(169)	—
Cash flows from financing activities:			
Proceeds from issuance of long-term debt, net of costs	247	(2)	—
Repayments of long-term debt	(251)	—	(17)
Dividends paid	(77)	(20)	(114)
Net cash flows from financing activities	(81)	(22)	(131)
Net change in cash and cash equivalents	6	6	45
Cash and cash equivalents at beginning of period	61	55	10
Cash and cash equivalents at end of period	$ 67	$ 61	$ 55

The accompanying notes are an integral part of these consolidated financial statements.

(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 Consolidation and Presentation

The Consolidated Financial Statements include the accounts of the Company and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated.

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

As a result of the MEHC Merger, the Company has elected to present its Consolidated Financial Statements and Notes to Consolidated 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.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated 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 Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

The Company prepares its Consolidated 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 Consolidated 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 Consolidated 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 Consolidated 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 Consolidated Statements of Operations.

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 Consolidated 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 Consolidated Statements of Operations. 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 Consolidated 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 Consolidated Statements of Operations.

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 Consolidated 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 consolidated 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 Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

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 Consolidated 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 Consolidated Statements of Operations.

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 Consolidated 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 Consolidated 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 Consolidated 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 Consolidated Statements of Operations 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 Consolidated Statements of Operations 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%, 2.94% and 2.89% during 2013, 2012 and 2011, 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 Consolidated Statements of Operations for the year ended December 31, 2013 related to the recovery of certain assets not currently in rates.

Sale of California Electric Distribution and Generation Assets

In January 2011, the Company sold its California electric distribution and generation assets to California Pacific Electric Company. Cash proceeds from the sale were $132 million, plus additional closing adjustments. Final accounting was approved by the FERC in September 2011. In connection with the sale of the assets, the Company entered into a separate five year purchase power agreement to sell energy to California Pacific Electric Company.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Company, as tenants in common, has undivided interests in jointly owned generation, and transmission facilities. The Company accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on the Consolidated Statements of Operations include the Company's share of the expenses of these facilities. The amounts shown in the table below represent the Company's share in each jointly owned facility as of December 31, 2013 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50%	$ 338	$ 211	$ 18
ON Line Transmission Line[1]	1	7	—	4
Valmy Transmission	50	4	2	—
Total		$ 349	$ 213	$ 22

(1) ON Line was placed in-service December 2013. The Company and Nevada Power entered into a long-term transmission use agreement with Great Basin Transmission South, LLC's 75% interest in ON Line. Refer to Note 8 for additional information.

(6) Regulatory Matters

Regulatory assets represent costs that are expected to be recovered in future rates. The Company's regulatory assets reflected on the Consolidated 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 Consolidated 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 Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated 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 Consolidated Statements of Operations 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 Consolidated 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.

(7) 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.

(8) 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.

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

(9) 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 Consolidated 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 Consolidated 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

(10) Other, Net

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

	2013	2012	2011
Interest and dividend income	$ 1	$ 1	$ 1
Donations	—	(1)	(2)
Interest expense on regulatory items	(1)	(1)	(5)
Other	6	(3)	(10)
Total other, net	$ 6	$ (4)	$ (16)

(11) Income Taxes

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

	2013	2012	2011
Current – Federal	$ (2)	$ (7)	$ —
Deferred:			
Federal	38	48	33
State	(2)	—	—
Total deferred	36	48	33
Investment tax credits	(1)	(1)	(2)
Total income tax expense	$ 33	$ 40	$ 31

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	2011
Federal statutory income tax rate	35%	35%	35%
Effects of ratemaking	1	(1)	—
Non-deductible MEHC Merger related expenses	1	—	—
Other	—	(2)	(1)
Effective income tax rate	37%	32%	34%

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)
Net deferred income tax liability	$ (477)	$ (444)
Reflected as:		
Deferred income taxes - current	$ 48	$ 22
Deferred income taxes - long-term	(525)	(466)
Net deferred income tax liability	$ (477)	$ (444)

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.

(12) Related Party Transactions

The Company provided electricity and other services to PacifiCorp, an indirect subsidiary of MEHC, of $- million, $3 million and $7 million for the years ended December 31, 2013, 2012 and 2011, respectively. PacifiCorp provided electricity to the Company of $- million, $- million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The Company provided electricity to Nevada Power of $1 million, $1 million and $2 million for the years ended December 31, 2013, 2012 and 2011, respectively. The Company purchased electricity from Nevada Power of $36 million, $20 million and $22 million for the years ended December 31, 2013, 2012 and 2011, respectively. The Company provided intercompany administrative services to Nevada Power of $22 million, $22 million and $22 million for the years ended December 31, 2013, 2012 and 2011, respectively. Nevada Power provided intercompany administrative services to the Company of $24 million, $20 million and $18 million for the years ended December 31, 2013, 2012 and 2011, respectively. As of December 31, 2013 and 2012, the Company's Consolidated 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, $12 million and $10 million for the years ended December 31, 2013, 2012 and 2011, respectively. As of December 31, 2013 and 2012, the Company's Consolidated Balance Sheets included amounts due to NV Energy of $28 million and $24 million as of December 31, 2013 and 2012, respectively.

(13) 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, $15 million and $25 million to the Qualified Pension Plan and $5 million, $7 million and $1 million to the Other Postretirement Plans for the years ended December 31, 2013, 2012 and 2011, respectively. The Company did not make any contributions to the Non-Qualified Pension Plans for the years ended December 31, 2013, 2012 and 2011. 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 Consolidated 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)

(14) 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 Consolidated 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 Consolidated Balance Sheets.

(15) Commitments and Contingencies

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated 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, 2012 and 2011 were $63 million, $60 million and $63 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

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 and $7 million for 2011.

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 consolidated 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, 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, estimated by Newmont to be $11 million.

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 is undertaking efforts at FERC under the Dispute Resolution provisions of the interconnection agreement. The issue of who is to pay for the protection equipment and its installation was not decided by the district court, and is pending before the FERC in Docket No. EL14-16-000. Management cannot predict the outcome of this matter at this time.

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.

(16) 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	2011
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 59	$ 60	$ 60
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 37	$ 27	$ 20
ON Line transmission use financial lease obligation	$ 22	$ —	$ —

(17) Segment Information

The Company has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by the PUCN; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance.

The Company believes presenting gross margin allows the reader to assess the impact of the Company's regulatory treatment and its overall regulatory environment on a consistent basis and is meaningful. Gross margin is calculated as operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale.

The following tables provide information on a reportable segment basis for the years ended December 31 (in millions):

2013

	Electric	Natural Gas	Total
Operating revenue	$ 747	$ 106	$ 853
Cost of fuel, energy and capacity	292	—	292
Natural gas purchased for resale	—	56	56
Gross margin	$ 455	$ 50	505
Operating and maintenance expense			197
Depreciation and amortization			123
Property and other taxes			25
Merger-related expenses			20
Interest expense, net of allowance for debt funds			60
Allowance for equity funds			(2)
Other, net			(6)
Income before income tax expense			$ 88
Total assets	$ 2,957	$ 335	$ 3,369 (1)
Capital expenditures	$ 141	$ 16	$ 157

2012

	Electric	Natural Gas	Total
Operating revenue	$ 726	$ 108	$ 834
Cost of fuel, energy and capacity	263	—	263
Natural gas purchased for resale	—	62	62
Gross margin[(2)]	$ 463	$ 46	509
Operating and maintenance expenses			190
Depreciation and amortization			108
Property and other taxes			23
Interest expense, net of allowance for debt funds			63
Allowance for equity funds			(3)
Other, net			4
Income before income tax expense			$ 124
Total assets	$ 2,919	$ 319	$ 3,316 [(1)]
Capital expenditures	$ 191	$ 20	$ 211

2011

	Electric	Natural Gas	Total
Operating revenue	$ 716	$ 173	$ 889
Cost of fuel, energy and capacity	273	—	273
Natural gas purchased for resale	—	124	124
Gross margin[(2)]	$ 443	$ 49	492
Operating and maintenance expenses			192
Depreciation and amortization			106
Property and other taxes			23
Interest expense, net of allowance for debt funds			67
Allowance for equity funds			(3)
Other, net			16
Income before income tax expense			$ 91
Total assets	$ 2,845	$ 308	$ 3,216 [(1)]
Capital expenditures	$ 133	$ 13	$ 146

(1) Certain assets totaling $77 million, $78 million and $63 million for the years ended 2013, 2012 and 2011, respectively, consisting principally of cash and cash equivalents are not included in either the regulated electric or regulated natural gas segments.

(2) Energy efficiency program costs were reclassified from gross margin to operating and maintenance expenses for presentation purposes.

(18) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
Regulated electric operating revenue	$ 172	$ 175	$ 213	$ 187
Regulated natural gas operating revenue	40	20	14	32
Operating income	49	30	58	3
Net income	22	11	29	(7)

	Three-Month Periods Ended			
	March 31, 2012	June 30, 2012	September 30, 2012	December 31, 2012
Regulated electric operating revenue	$ 170	$ 168	$ 212	$ 176
Regulated natural gas operating revenue	46	20	12	30
Operating income	45	35	66	42
Net income	19	13	34	18

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the President (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the President (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to management, including the Company's President (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in the Company's internal control over financial reporting during the quarter ended December 31, 2013 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the President (principal executive officer) and the Chief Financial Officer (principal financial officer), the Company's management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2013 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control - Integrated Framework (1992)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (1992)", the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

Sierra Pacific Power Company
March 31, 2014

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 11. Executive Compensation

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) for Form 10-K.

Item 14. Principal Accountant Fees and Services

The following table shows the Company's fees paid or accrued for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu Limited, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2013	2012
Audit fees(1)	$ 1.1	$ 1.0
Audit-related fees(2)	—	—
Tax fees(3)	—	—
Total	$ 1.1	$ 1.0

(1) Audit fees include fees for the audit of the Company's consolidated financial statements and interim reviews of the Company's quarterly financial statements, audit services provided in connection with required statutory audits, comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of employee benefit plans and consultations on various accounting and reporting matters.

(3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal and state tax compliance, tax return preparation and tax audits.

The audit committee of MEHC has considered whether the non-audit services provided to the Company by the Deloitte Entities impaired the independence of the Deloitte Entities and concluded that they did not. All of the services performed by the Deloitte Entities were pre-approved in a manner consistent with the pre-approval policy adopted by the audit committee of MEHC. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to the Company. The policy (a) identifies the guiding principles that must be considered by the audit committee of MEHC in approving services to ensure that the Deloitte Entities' independence is not impaired; (b) describes the audit, audit-related and tax services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services. Under the policy, requests to provide services that require specific approval by the audit committee of MEHC will be submitted to the audit committee of MEHC by both the Company's independent auditor and MEHC's Chief Financial Officer. All requests for services to be provided by the independent auditor that do not require specific approval by the audit committee of MEHC will be submitted to MEHC's Chief Financial Officer and must include a detailed description of the services to be rendered. MEHC's Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the audit committee of MEHC. The audit committee of MEHC will be informed on a timely basis of any such services rendered by the independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedule

(i) Financial Statements:

Consolidated Financial Statements are included in Item 8 37

(ii) Financial Statement Schedules:

See Schedule II. 66

Schedules not listed above have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(b) Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report. 68

(c) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3(b).

Not applicable.

SIERRA PACIFIC POWER COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2013
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserve for uncollectible accounts receivable:				
Year ended 2013	$ 1	$ 2	$ (2)	$ 1
Year ended 2012	1	1	(1)	1
Year ended 2011	2	2	(3)	1

The notes to the consolidated financial statements are an integral part of this financial statement schedule.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 31st day of March 2014.

SIERRA PACIFIC POWER COMPANY

/s/ Paul J. Caudill
Paul J. Caudill
President and Director
(principal executive officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	President and Director (principal executive officer)	March 31, 2014
/s/ E. Kevin Bethel E. Kevin Bethel	Senior Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	March 31, 2014
/s/ Douglas A. Cannon Douglas A. Cannon	Senior Vice President, Corporate Secretary, General Counsel and Director	March 31, 2014
/s/ Patrick S. Egan Patrick S. Egan	Senior Vice President, Customer Services and Director	March 31, 2014
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	March 31, 2014
/s/ Francis P. Gonzales Francis P. Gonzales	Director	March 31, 2014
/s/ John C. Owens John C. Owens	Director	March 31, 2014
/s/ Tony F. Sanchez, III Tony F. Sanchez, III	Senior Vice President, Government and Community Strategy and Director	March 31, 2014

EXHIBIT INDEX

Exhibits Filed Herewith

Exhibit No.	Description
12.1	Computation of Ratios of Earnings to Fixed Charges.
14.1	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers.
23.1	Consent of Deloitte & Touche LLP.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following financial information from Sierra Pacific Power Company's Annual Report on Form 10-K for the year ended December 31, 2013 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Shareholder's Equity, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements, tagged in summary and detail.

Exhibits Incorporated by Reference

Exhibit No.	Description
3.1	Restated Articles of Incorporation of Sierra Pacific Power Company, dated October 25, 2006 (filed as Exhibit 3.1 to Form 10-Q for quarter ended September 30, 2006).
3.2	By-Laws of Sierra Pacific Power Company, as amended through November 13, 1996 (filed as Exhibit (3)(A) to Form 10-K for the year ended December 31, 1996).
4.1	General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York as Trustee (filed as Exhibit 4.2(a) to Form 10-Q for the quarter ended June 30, 2001).
4.2	Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (filed as Exhibit 4(A) to Form 10-K for the year ended December 31, 2006).
4.3	Agreement of Resignation, Appointment and Acceptance dated November 6, 2009 by and among Sierra Pacific Power Company d/b/a NV Energy, The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (filed as Exhibit 4.3 to Form 10-K for the year ended December 31, 2009).
4.4	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4.4 to Form 10-Q for the quarter ended March 31, 2006).
4.5	Form of First Supplemental Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4.2 to Form 8-K dated August 18, 2009).
4.6	Form of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Appendix A to Exhibit 4.2 to Form 8-K dated August 18, 2009).
4.7	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (filed as Exhibit 4.2 to Form 8-K dated June 27, 2007).

Exhibit No.	Description
4.8	Form of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (filed as Appendix A to Exhibit 4.2 to Form 8-K dated June 27, 2007).
4.9	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 3.375% General and Refunding Mortgage Notes, Series T, due 2023 (filed as Exhibit 4.1 to Form 8-K dated August 12, 2013).
4.10	Form of Sierra Pacific Power Company's 3.375% General and Refunding Mortgage Notes, Series T, due 2023 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated August 12, 2013).
10.1	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2010).
10.2	Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007A) (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2007).
10.3	Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007B) (filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2007).
10.4	Financing Agreement dated November 1, 2006 between Humboldt County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Humboldt County, Nevada $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006) (filed as Exhibit 10(B) to Form 10-K for the year ended December 31, 2006).
10.5	Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $58,750,000 Gas Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006A) (filed as Exhibit 10(C) to Form 10-K for the year ended December 31, 2006).
10.6	Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $75,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006B) (filed as Exhibit 10(D) to Form 10-K for the year ended December 31, 2006).
10.7	Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $84,800,000 Gas and Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006C) (filed as Exhibit 10(E) to Form 10-K for the year ended December 31, 2006).
10.8	Credit Agreement dated March 23, 2012 between Sierra Pacific Power Company d/b/a NV Energy and Wells Fargo Bank, N.A., as administrative agent for the lenders (filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 30, 2012).

EXHIBIT 12.1

SIERRA PACIFIC POWER COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Millions)

	Years Ended December 31,				
	2013	2012	2011	2010	2009
Earnings available for fixed charges:					
Net income	$ 55	$ 84	$ 60	$ 72	$ 73
Add (deduct):					
Income tax expense	33	40	31	40	31
Fixed charges	62	66	70	73	75
Capitalized interest (allowance for borrowed funds used during construction)	(2)	(2)	(2)	(2)	(3)
	93	104	99	111	103
Total earnings available for fixed charges	$ 148	$ 188	159	$ 183	$ 176
Fix charges:					
Interest on long-term debt	62	66	70	73	75
Total fixed charges	$ 62	$ 66	$ 70	$ 73	$ 75
Ratio of earnings to fixed charges	2.39	2.85	2.27	2.51	2.35

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense.

For the purpose of calculating the ratios of earnings to fixed charges, "Earnings" represents net income adjusted for income taxes plus fixed charges (excluding capitalized interest). "Fixed Charges" represent the aggregate of interest charges on long-term debt (whether expensed or capitalized) and the portion or rental expense deemed attributable to interest.

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-190869-01 on Form S-3 of our report dated March 31, 2014 relating to the consolidated financial statements and consolidated financial statement schedule of Sierra Pacific Power Company and subsidiaries appearing in this Annual Report on Form 10-K of Sierra Pacific Power Company for the year ended December 31, 2013.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
March 31, 2014

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY)
(“Registrant”)

I, Paul J. Caudill, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2013 of Sierra Pacific Power Company (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

March 31, 2014

/s/ Paul J. Caudill
Paul J. Caudill
President
Sierra Pacific Power Company (dba NV Energy)
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER REQUIRED BY SECTION 302(A) OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY)
("Registrant")

I, E. Kevin Bethel, certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2013 of Sierra Pacific Power Company (dba NV Energy);

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)), for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 31, 2014

/s/ E. Kevin Bethel
E. Kevin Bethel
Chief Financial Officer
Sierra Pacific Power Company (dba NV Energy)
(Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

SIERRA PACIFIC POWER COMPANY (dba NV ENERGY)
("Registrant")

In connection with this report of Sierra Pacific Power Company (dba NV Energy) on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof, I, Paul J. Caudill, President of registrant, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ Paul J. Caudill
Paul J. Caudill
President
Sierra Pacific Power Company (dba NV Energy)
(Principal Executive Officer)
March 31, 2014

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

**SIERRA PACIFIC POWER COMPANY (dba NV ENERGY)
(“Registrant”)**

In connection with this report of Sierra Pacific Power Company (dba NV Energy) on Form 10-K for the year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof, I, E. Kevin Bethel, Chief Financial Officer of registrant, certify, pursuant to 18 U.S.C. §1350, as adopted pursuant to §906 of the Sarbanes-Oxley Act of 2002, that:

1. This report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

2. The information contained in this report fairly presents, in all material respects, the financial condition and results of operations of the registrant.

/s/ E. Kevin Bethel
E. Kevin Bethel
Chief Financial Officer
Sierra Pacific Power Company (dba NV Energy)
(Principal Financial Officer)
March 31, 2014

This Certification accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by the Sarbanes-Oxley Act of 2002, be deemed filed by the registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent the registrant specifically incorporates it by reference.

A signed original of this written statement required by Section 906 has been provided to the registrant and will be retained by the registrant and furnished to the Securities and Exchange Commission or its staff upon request.