NV Energy, Inc. and Subsidiaries

Consolidated Financial Statements (Unaudited)
as of and for the
Years Ended December 31, 2015 and 2014

and

Management's Discussion and Analysis
of Financial Condition and Results of Operations

NV ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in millions, except share data)

	As of December 31, 2015	As of December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 634	$ 262
Accounts receivable, net	363	349
Inventories	119	128
Regulatory assets	—	89
Other current assets	59	52
Total current assets	1,175	880
Property, plant and equipment, net	9,762	9,643
Regulatory assets	1,487	1,510
Other assets	54	58
Total assets	$ 12,478	$ 12,091
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 270	$ 294
Accrued interest	71	78
Accrued property and other taxes	43	42
Regulatory liabilities	251	78
Current portion of long-term debt and financial and capital lease obligations	678	265
Customer deposits	75	71
Other current liabilities	39	49
Total current liabilities	1,427	877
NV Energy long-term debt	313	312
Subsidiary long-term debt and financial and capital lease obligations	3,809	4,469
Regulatory liabilities	534	589
Deferred income taxes	1,852	1,680
Other long-term liabilities	449	430
Total liabilities	8,384	8,357
Commitments and contingencies (Note 14)		
Equity:		
Common stock - 1,000 shares authorized, $.01 par value, 1 share issued and outstanding	—	—
Other paid-in capital	3,128	3,128
Retained earnings	970	610
Accumulated other comprehensive loss, net	(4)	(4)
Total equity	4,094	3,734
Total liabilities and equity	$ 12,478	$ 12,091

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

NV ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)
(Amounts in millions)

	Years Ended December 31,	
	2015	2014
Operating revenue:		
Regulated electric	$ 3,212	$ 3,115
Regulated natural gas	137	125
Nonregulated	2	1
Total operating revenue	3,351	3,241
Operating costs and expenses:		
Cost of fuel, energy and capacity	1,458	1,437
Natural gas purchased for resale	84	76
Operating and maintenance	531	568
Depreciation and amortization	410	379
Property and other taxes	72	68
Total operating costs and expenses	2,555	2,528
Operating income	796	713
Other income (expense):		
Interest expense	(272)	(292)
Allowance for borrowed funds	5	3
Allowance for equity funds	6	4
Other, net	25	35
Total other income (expense)	(236)	(250)
Income before income tax expense	560	463
Income tax expense	200	167
Net income	$ 360	$ 296

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

NV ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Unaudited)
(Amounts in millions, except per share data)

	Common Stock		Other Paid-in	Retained	Accumulated Other Comprehensive	Total
	Shares	Amount	Capital	Earnings	Loss, Net	Equity
Balance, December 31, 2013	—	$ —	$ 3,023	$ 619	$ (9)	$ 3,633
Net income	—	—	—	296	—	296
Dividends declared	—	—	—	(305)	—	(305)
Contributions from parent	—	—	105	—	—	105
Other	—	—	—	—	5	5
Balance, December 31, 2014	—	—	3,128	610	(4)	3,734
Net income	—	—	—	360	—	360
Balance, December 31, 2015	—	$ —	$ 3,128	$ 970	$ (4)	$ 4,094

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

NV ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

	Years Ended December 31,	
	2015	**2014**
Cash flows from operating activities:		
Net income	$ 360	$ 296
Adjustments to reconcile net income to net cash from operating activities:		
(Gain) loss on nonrecurring items	(3)	29
Depreciation and amortization	410	379
Deferred income taxes and amortization of investment tax credits	200	167
Allowance for equity funds	(6)	(4)
Changes in regulatory assets and liabilities	(17)	(31)
Deferred energy	257	(74)
Amortization of deferred energy	53	98
Other, net	8	92
Changes in other assets and liabilities:		
Accounts receivable and other assets	(20)	21
Inventories	10	(12)
Accounts payable and other liabilities	(58)	(25)
Net cash flows from operating activities	1,194	936
Cash flows from investing activities:		
Capital expenditures	(572)	(557)
Proceeds from sale of asset	9	—
Purchases of marketable securities	(7)	—
Proceeds from sale of marketable securities	12	—
Net cash flows from investing activities	(558)	(557)
Cash flows from financing activities:		
Repayments of NV Energy long-term debt	—	(195)
Repayments of subsidiary long-term debt and financial and capital lease obligations	(263)	(8)
Contributions from parent	—	105
Dividends paid	—	(305)
Other, net	(1)	(1)
Net cash flows from financing activities	(264)	(404)
Net change in cash and cash equivalents	372	(25)
Cash and cash equivalents at beginning of period	262	287
Cash and cash equivalents at end of period	$ 634	$ 262

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

(1) Organization and Operations

NV Energy, Inc. ("NV Energy") is a holding company that owns Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific") (collectively, the "Nevada Utilities") and certain other subsidiaries (collectively, the "Company"). The Nevada Utilities, which do business as NV Energy, are public utilities that provide electric service to 1.2 million regulated retail electric customers and 0.2 million regulated retail natural gas customers in Nevada. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of NV Energy 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 Company has evaluated subsequent events through March 15, 2016.

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 Nevada Utilities prepare their Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Nevada Utilities defer 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 Nevada Utilities continually evaluate 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 Nevada Utilities' ability to recover their costs. The Nevada Utilities believe 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).

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 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 collectibility 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. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net on the Consolidated Balance Sheets, is summarized as follows for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 16	$ 9
Charged to operating costs and expenses, net	17	16
Write-offs, net	(19)	(9)
Ending balance	$ 14	$ 16

Derivatives

The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price 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. Derivative balances reflect offsetting permitted under master netting agreements with counterparties and cash collateral paid or received under such agreements.
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.

Inventories

Inventories consist mainly of materials and supplies totaling $92 million and $90 million as of December 31, 2015 and 2014, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $27 million and $38 million as of December 31, 2015 and 2014, 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 Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Nevada Utilities capitalize 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 Nevada Utilities' various regulatory authorities. Depreciation studies are completed by the Nevada Utilities 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 a cost of removal regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when the Nevada Utilities retire or sell a component of regulated property, plant and equipment, they charge 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 represent 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. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, the Nevada Utilities are 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. Nevada Power's AFUDC rate used during 2015 and 2014 was 8.09%. Sierra Pacific's AFUDC rate used during 2015 and 2014 was 7.62% and 7.58%, respectively, for electric, 5.97% and 4.96% for natural gas and 7.44% and 7.28% for common facilities, respectively.

Asset Retirement Obligations

The Nevada Utilities recognize asset retirement obligations ("ARO") when they have a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Nevada Utilities' 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, net) 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 Nevada Utilities' 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 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 and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2015, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

Berkshire Hathaway includes the Company in its United States federal income tax return. 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 Nevada Utilities are required to pass on to their customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2015 and 2014, these amounts were recognized as regulatory assets of $239 million and $250 million, respectively, and regulatory liabilities of $17 million and $11 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, state 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 to be realized upon ultimate settlement. Although the ultimate resolution of the Company's federal, state and local 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. 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, 2015 and 2014, unbilled revenue was $175 million and $168 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 Nevada Utilities primarily buy energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, the Nevada Utilities may not take physical delivery of the energy or natural gas. The Nevada Utilities' may sell the excess energy or natural gas to the wholesale market. In such instances, it is the Nevada Utilities' policy to record such sales net in cost of fuel, energy and capacity.

Unamortized Debt Premiums, Discounts and Issuance 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 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2016-02, which creates FASB Accounting Standards Codification (“ASC”) Topic 842, “Leases” and supersedes Topic 840 “Leases.” This guidance increases transparency and comparability among entities by recording lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. A lessee should recognize in the balance sheet a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous guidance. This guidance is effective for interim and annual reporting periods beginning after December 15, 2018, with early adoption permitted, and is required to be adopted using a modified retrospective approach. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2015, the FASB issued ASU No. 2015-17, which amends FASB ASC Topic 740, "Income Taxes." The amendments in this guidance require that deferred income tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted, and may be adopted prospectively or retrospectively for each period presented to reflect the new guidance. The Company early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in decreases in current deferred income tax assets and noncurrent deferred income tax liabilities of $178 million as of December 31, 2014.

In April 2015, the FASB issued ASU No. 2015-03, which amends FASB ASC Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. The Company early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in a decrease in other assets and long-term debt of $45 million as of December 31, 2014.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB ASC Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2015	2014
Utility plant in-service:			
Electric generation	25 - 125 years	$ 5,346	$ 5,070
Electric distribution	20 - 70 years	4,500	4,339
Electric transmission	45 - 70 years	2,527	2,476
Electric general and intangible plant	5 - 65 years	833	792
Natural gas distribution	40 - 70 years	374	366
Natural gas general and intangible plant	8 - 10 years	13	13
Common general	5 - 65 years	265	234
Utility plant in-service		13,858	13,290
Accumulated depreciation and amortization		(4,339)	(3,899)
Utility plant in-service, net		9,519	9,391
Other non-regulated, net of accumulated depreciation and amortization	5 - 65 years	2	4
Plant, net		9,521	9,395
Construction work-in-progress		241	248
Property, plant and equipment, net		$ 9,762	$ 9,643

Almost all of the Company's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Nevada Power's depreciation and amortization, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2015 and 2014 was 3.0% and 3.3%, respectively, while Sierra Pacific's depreciation and amortization as of December 31, 2015 and 2014 was 2.9% and 3.0%, respectively. The Nevada Utilities are 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 Nevada Utilities recorded an impairment charge of $41 million in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014 related to the recovery of certain assets not currently in rates. Included in the 2014 impairment is $27 million related to the settlement of the 2014 Nevada Power general rate case and the related Sierra Pacific companion filing. Impairments of regulated assets not in rates were not material in 2015.

(4) Regulatory Matters

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

	Weighted Average Remaining Life	2015	2014
Deferred income taxes[1]	28 years	$ 239	$ 250
Employee benefit plans[2]	10 years	235	212
Merger costs from 1999 merger	29 years	226	236
Abandoned projects	5 years	135	158
Decommissioning costs	7 years	121	114
Asset retirement obligations	9 years	91	92
Deferred operating costs	20 years	87	61
Legacy meters	16 years	83	89
Deferred energy costs	2 years	56	161
Other	Various	214	226
Total regulatory assets		$ 1,487	$ 1,599
Reflected as:			
Current assets		$ —	$ 89
Other assets		1,487	1,510
Total regulatory assets		$ 1,487	$ 1,599

(1) Amounts 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 $826 million and $1.0 billion as of December 31, 2015 and 2014, respectively, primarily related to deferred income taxes, merger costs from 1999 merger, asset retirement obligations, deferred operating costs, deferred excess energy costs, loss on reacquired debt, and legacy meters for Sierra Pacific. Regulatory assets not earning a return as of December 31, 2014 also included a portion of abandoned projects, legacy meters for Nevada Power and 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	2015	2014
Cost of removal[(1)]	37 years	$ 481	$ 528
Deferred energy costs	2 years	205	—
Renewable energy program	1 year	8	47
Other	Various	91	92
Total regulatory liabilities		$ 785	$ 667
Reflected as:			
Current liabilities		$ 251	$ 78
Other long-term liabilities		534	589
Total regulatory liabilities		$ 785	$ 667

(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 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 costs. 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

The PUCN 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 Nevada Utilities file annually to adjust energy efficiency program rates ("EEPR") and EEIR for over- or under-collected balances, which are effective in October of the same year.

The PUCN's final order approving the BHE Merger stipulated that the Nevada Utilities will not seek recovery of any lost revenue for calendar year 2013 and, for the calendar year 2014 in an amount that exceeds 50% of the lost revenue that the Nevada Utilities could otherwise request. In February 2014, the Nevada Utilities filed an application with the PUCN to reset the EEIR and EEPR. In June 2014, the PUCN accepted a stipulation to adjust the EEIR, as of July 1, 2014, to collect 50% of the estimated lost revenue that the Nevada Utilities would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014 and reset on January 1, 2015 and was in effect through September 2015.

In February 2015, the Nevada Utilities filed an application to reset the EEIR and EEPR. In August 2015, the PUCN accepted a stipulation for the Nevada Utilities to calculate the base EEIR using a revised methodology for calculating lost revenue and for the Nevada Utilities to make a $6 million reduction to the EEPR revenue requirement to more accurately reflect the actual level of spending and to minimize any over collection from its customers. The reset of the EEIR and EEPR was effective October 1, 2015 and remains in effect through September 30, 2016. To the extent the Nevada Utilities' earned rate of return exceeds the rate of return used to set base general rates, the Nevada Utilities are required to refund to customers EEIR revenue collected. The current EEIR liability for the Nevada Utilities is $21 million and $13 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

General Rate Case

In May 2014, Nevada Power filed a general rate case with the PUCN. In July 2014, Nevada Power made its certification filing, which requested incremental annual revenue relief in the amount of $38 million, or an average price increase of 2%. In October 2014, Nevada Power reached a settlement agreement with certain parties agreeing to a zero increase in the revenue requirement. In October 2014, the PUCN issued an order in the general rate case filing that accepted the settlement. The order provides for increases in the fixed-monthly service charge for customers with a corresponding decrease in the base tariff general rate effective January 1, 2015. As a result of the order, Nevada Power recorded $15 million in asset impairments related to property, plant and equipment and $5 million of regulatory asset impairments, which are included in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014. Additionally, Nevada Power recorded a $5 million gain in other, net on the Consolidated Statement of Operations for the year ended December 31, 2014 related to the disposition of property. In October 2014, a party filed a petition for reconsideration of the PUCN order. In November 2014, the PUCN granted the petition for reconsideration and reaffirmed the order issued in October 2014.

In connection with Nevada Power's general rate case filing in May 2014, as required by the PUCN, Sierra Pacific made a "companion filing" for the purpose of documenting the costs and benefits of Sierra Pacific's investment in the advanced service delivery program. In October 2014, the PUCN issued an order in the companion filing issued with the Nevada Power general rate case order that, among other things, provided for the implementation of new rates effective January 1, 2015 to begin recovery of costs associated with advance service delivery. The recovery of advanced service delivery costs increased annual revenue approximately $10 million. As a result of the PUCN order in the companion filing issued with the Nevada Power general rate case order, Sierra Pacific recorded $7 million in asset impairments related to property, plant and equipment and $1 million of regulatory asset impairments, which are included in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014.

2013 FERC Transmission Rate Case

In May 2013, the Nevada Utilities 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. In August 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 Nevada Utilities implemented the filed rates in this case subject to refund as set forth in the FERC's order.

In September 2014, the Nevada Utilities filed an unopposed settlement offer with the FERC on behalf of NV Energy and the intervening parties providing rate relief of $4 million. The settlement offer would resolve all outstanding issues related to this case. In addition, a preliminary order from the administrative law judge granting the motion for interim rate relief was issued, which authorizes the Nevada Utilities to institute the interim rates effective September 1, 2014, and begin billing transmission customers under the settlement rates for service provided on and after that date. In January 2015, the FERC approved the settlement and refunds were issued.

(5) Credit Facilities

Nevada Power

Nevada Power has a $400 million secured credit facility expiring in March 2018. The credit facility, which is for general corporate purposes for the issuance of letters of credit, has a variable interest rate based on London Interbank Offered Rate or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's credit ratings for its senior secured long-term debt securities. As of December 31, 2015 and 2014, Nevada Power had no borrowings outstanding under the credit facility. Amounts due under Nevada Power's credit facility are collateralized by Nevada Power's general and refunding mortgage bonds. The credit facility requires Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

Sierra Pacific

Sierra Pacific has a $250 million secured credit facility expiring in March 2018. The credit facility, which is for general corporate purposes for the issuance of letters of credit, has a variable interest rate based on London Interbank Offered Rate or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's credit ratings for its senior secured long-term debt securities. As of December 31, 2015 and 2014, Sierra Pacific had no borrowings outstanding under the credit facility. Amounts due under Sierra Pacific's credit facility are collateralized by Sierra Pacific's general and refunding mortgage bonds. The credit facility requires Sierra Pacific's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

(6) NV Energy Long-Term Debt

NV Energy's long-term debt consists of the following as of December 31 (in millions):

	Par Value	2015	2014
6.25% Senior Notes, due 2020	$ 315	$ 313	$ 312

(7) Subsidiary Long-Term Debt and Financial and Capital Lease Obligations

NV Energy's subsidiary long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs as of December 31 (dollars in millions):

	Par Value	2015	2014
Nevada Power:			
General and Refunding Mortgage Securities:			
5.875% Series L, due 2015	$ —	$ —	$ 250
5.950% Series M, due 2016	210	210	209
6.500% Series O, due 2018	324	323	322
6.500% Series S, due 2018	499	498	497
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	356	356
6.750% Series R, due 2037	349	345	345
5.375% Series X, due 2040	250	247	247
5.450% Series Y, due 2041	250	235	234
Variable-rate series (2015-0.672% to 1.055%, 2014-0.455% to 0.464%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	37	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	497	497	510
Total Nevada Power long-term debt and financial and capital lease obligations	3,322	3,285	3,544
Sierra Pacific:			
General and Refunding Mortgage Securities:			
6.000% Series M, due 2016	450	450	451
3.375% Series T, due 2023	250	248	247
6.750% Series P, due 2037	252	255	255
Variable-rate series (2015-0.733% to 1.054%, 2014-0.464% to 0.466%):			
Pollution Control Revenue Bonds Series 2006A, due 2031	58	58	58
Pollution Control Revenue Bonds Series 2006B, due 2036	75	74	74
Pollution Control Revenue Bonds Series 2006C, due 2036	81	80	79
Capital and financial lease obligations - 2.700% to 8.548%, due through 2054	37	37	26
Total Sierra Pacific long-term debt and financial and capital lease obligations	1,203	1,202	1,190
Total subsidiary long-term debt and financial and capital lease obligations	$ 4,525	$ 4,487	$ 4,734
Reflected as:			
Current portion of long-term debt and financial and capital lease obligations		$ 678	$ 265
Subsidiary long-term debt and financial and capital lease obligations		3,809	4,469
Total subsidiary long-term debt and financial and capital lease obligations		$ 4,487	$ 4,734

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2016 and thereafter, are as follows (in millions):

	Long-term Debt			Capital and Financial Lease Obligations			
	NV Energy	**Nevada Power**	**Sierra Pacific**	**NV Energy**	**Nevada Power**	**Sierra Pacific**	**Total**
2016	$ —	$ 210	$ 450	$ —	$ 73	$ 6	$ 739
2017	—	—	—	—	75	4	79
2018	—	823	—	—	74	4	901
2019	—	500	—	—	75	4	579
2020	—	—	—	—	74	3	77
Thereafter	313	1,292	716	—	908	53	3,282
Total	313	2,825	1,166	—	1,279	74	5,657
Unamortized premium, discount and debt issuance cost	—	(37)	(1)	—	—	—	(38)
Executory costs	—	—	—	—	(129)	—	(129)
Amounts representing interest	—	—	—	—	(653)	(37)	(690)
Total	$ 313	$ 2,788	$ 1,165	$ —	$ 497	$ 37	$ 4,800

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures for each of Nevada Power and Sierra Pacific. As of December 31, 2015, approximately $8.7 billion of Nevada Power's and $3.7 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- In 1984, Nevada Power entered into a 30-year capital lease for the Pearson Building with five, five-year renewal options beginning in year 2015. In February 2010, Nevada Power amended this capital lease agreement to include the lease of the adjoining parking lot and to exercise three of the five-year renewal options beginning in year 2015. There remain two additional renewal options which could extend the lease an additional ten years. Capital assets of $27 million and $28 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.

- In 2007, Nevada Power entered into a 20-year lease, with three 10-year renewal options, to occupy land and building for its Beltway Complex operations center in southern Nevada. Nevada Power accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. Nevada Power transferred operations to the facilities in June 2009. Capital assets of $7 million and $8 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.

- Nevada Power has long-term energy purchase contracts which qualify as capital leases. The leases were entered into between the years 1989 and 1990 and firm operation occurred through 1993. The terms of the leases are for 30 years and expire between the years 2022-2023. Capital assets of $40 million and $44 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.

- The Nevada Utilities have 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. Capital assets of $4 million were included in property, plant and equipment, net as of December 31, 2015 and 2014.

- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 95% for Nevada Power and 5% for Sierra Pacific. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $432 million and $440 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.

- In 2015, Sierra Pacific entered into a 20-year capital lease for the Fort Churchill Solar Array. Capital assets of $12 million were included in property, plant and equipment, net as of December 31, 2015.

(8) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices and interest rates. The Company is principally exposed to electricity, natural gas and coal market fluctuations primarily through the Nevada Utilities' obligation to serve retail customer load in its regulated service territory. The Nevada Utilities' 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 and wholesale electricity that is purchased and sold. 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 actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. The Company does not engage in proprietary trading activities.

The Company has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. 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. 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. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Notes 2, 4 and 9 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Company's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2015			
Commodity liabilities[1]	$ (8)	$ (14)	$ (22)
As of December 31, 2014			
Commodity liabilities[1]	$ (10)	$ (21)	$ (31)

(1) The Company's commodity derivatives not designated as hedging contracts are included in regulated rates and as of December 31, 2015 and 2014, a regulatory asset of $22 million and $31 million, respectively, was recorded related to the derivative liability of $22 million and $31 million, respectively.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding derivative contracts with indexed and fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

	Unit of Measure	2015	2014
Electricity sales	Megawatt hours	(2)	(3)
Natural gas purchases	Decatherms	175	161

Credit Risk

The Company is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent the Company's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, the Company analyzes the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, the Company enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, the Company exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain credit support provisions that in part base certain collateral requirements on credit ratings for unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide rights to demand cash or other security in the event of a credit rating downgrade ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features was $4 million, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(9) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, 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 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 following table presents the Company's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements			
	Level 1	**Level 2**	**Level 3**	**Total**
As of December 31, 2015				
Assets:				
Money market mutual funds[1]	$ 3	$ —	$ —	$ 3
Investment funds	13	—	—	13
	$ 16	$ —	$ —	$ 16
Liabilities - commodity derivatives	$ —	$ —	$ (22)	$ (22)
As of December 31, 2014				
Assets:				
Money market mutual funds[1]	$ 2	$ —	$ —	$ 2
Investment funds	24	—	—	24
	$ 26	$ —	$ —	$ 26
Liabilities - commodity derivatives	$ —	$ —	$ (31)	$ (31)

(1) Amounts are included in other assets on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

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. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of the Company's nonperformance risk on its liabilities, which as of December 31, 2015 and 2014, had an immaterial impact to the fair value of its derivative contracts. As such, the Company considers its derivative contracts to be valued using Level 3 inputs. Refer to Note 8 for further discussion regarding the Company's risk management and hedging activities.

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

The following table reconciles the beginning and ending balances of the Company's commodity derivative liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ (31)	$ (47)
Changes in fair value recognized in regulatory assets	—	8
Settlements	9	8
Ending balance	$ (22)	$ (31)

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):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 4,266	$ 4,844	$ 4,510	$ 5,915

(10) Income Taxes

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

	2015	2014
Deferred – Federal	202	169
Investment tax credits	(2)	(2)
Total income tax expense	$ 200	$ 167

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:

	2015	2014
Federal statutory income tax rate	35%	35%
Effects of ratemaking	1	1
Effective income tax rate	36%	36%

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

	2015	2014
Deferred income tax assets:		
Capital and financial leases	$ 187	$ 187
Federal net operating loss and credit carryforwards	176	326
Regulatory liabilities	66	58
Employee benefits	55	42
Other	55	76
Total deferred income tax assets	539	689
Valuation allowance	(5)	(2)
Total deferred income tax assets, net	534	687
Deferred income tax liabilities:		
Property related items	(1,778)	(1,649)
Regulatory assets	(399)	(490)
Capital and financial leases	(182)	(183)
Other	(27)	(45)
Total deferred income tax liabilities	(2,386)	(2,367)
Net deferred income tax liability	$ (1,852)	$ (1,680)

The following table provides the Company's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2015 (in millions):

Net operating loss carryforwards	$ 446
Deferred income taxes on federal net operating loss carryforwards	$ 156
Expiration dates	2031-2035
Other tax credits	$ 20
Expiration dates	2016-2035

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

(11) Related Party Transactions

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $68 million for each of the years ended December 31, 2015 and 2014. As of December 31, 2015 and 2014, the Company's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $5 million.

The Company provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $3 million for each of the years ended December 31, 2015 and 2014. There were no receivables associated with these services as of December 31, 2015 and 2014. PacifiCorp provided electricity and the sale of renewable energy credits to the Company of $2 million and $5 million for the years ended December 31, 2015 and 2014, respectively. Payables associated with these transactions were $- million and $4 million as of December 31, 2015 and 2014, respectively.

(12) Employee Benefit Plans

Defined Benefit Plans

NV Energy has a single employer defined benefit pension plan covering substantially all employees of NV Energy and the Nevada Utilities. Certain grandfathered and union employees are covered under a benefit formula based on years of service and the employee's highest compensation for a period prior to retirement, while most employees are covered under a cash balance formula with vesting after three years of service. NV Energy also has other postretirement plans, including a defined contribution plan which provides medical and life insurance benefits for certain retired employees, a non-qualified supplemental executive retirement plan ("SERP") and a non-qualified restoration plan ("Restoration") for certain executives.

Recent Plan Changes

In 2015, NV Energy amended the pension plan for new and rehired non-represented and Local 396 employees. Effective January 1, 2015, new and rehired non-represented employees receive an additional 4% employer contribution to their 401(k) plan as a replacement of the cash balance plan. Effective January 1, 2016, the same amendment was made for new and rehired Local 396 employees. In addition, NV Energy amended the other postretirement benefit plan to include Retiree Medical Retirement Health Reimbursement Account benefit for Local 396 employees and changed the life insurance benefit to $10,000 for non-represented employees.

SERP and Restoration lump sum payments made in 2014 were in excess of the 2014 interest cost plus service cost for both plans. This resulted in a settlement for the plans and required the immediate recognition of additional expense of $6 million and $1 million for SERP and Restoration, respectively.

NV Energy amended the other postretirement benefit plan in 2014 to cap the subsidies provided to certain participants at 2014 levels. This amendment decreased the benefit obligation by $1 million in 2014.

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Service cost	$ 17	$ 17	$ 2	$ 2
Interest cost	35	40	6	8
Expected return on plan assets	(46)	(43)	(8)	(7)
Net amortization	11	14	(3)	(2)
Net periodic benefit cost (credit)	$ 17	$ 28	$ (3)	$ 1

The average percentage of NV Energy net periodic benefit costs capitalized during 2015 and 2014 was 38.0% and 36.5%, respectively.

Funded Status

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Plan assets at fair value, beginning of year	$ 841	$ 818	$ 116	$ 110
Employer contributions	2	20	—	—
Participant contributions	—	—	2	2
Actual return on plan assets	(20)	82	(1)	16
Settlements	(23)	(48)	—	—
Benefits paid	(32)	(31)	(9)	(12)
Plan assets at fair value, end of year	$ 768	$ 841	$ 108	$ 116

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligation, beginning of year	$ 901	$ 823	$ 147	$ 154
Service cost	17	17	2	2
Interest cost	35	40	6	8
Participant contributions	—	—	2	2
Actuarial (gain) loss	(35)	100	(8)	(6)
Benefits paid	(32)	(31)	(9)	(12)
Amendment	(4)	—	3	(1)
Settlements	(23)	(48)	—	—
Benefit obligation, end of year	$ 859	$ 901	$ 143	$ 147
Accumulated benefit obligation, end of year	$ 844	$ 883		

The funded status of the plans and the amounts recognized on the Consolidated Balance Sheets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Plan assets at fair value, end of year	$ 768	$ 841	$ 108	$ 116
Benefit obligation, end of year	859	901	143	147
Funded status	$ (91)	$ (60)	$ (35)	$ (31)
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	$ (2)	$ (2)	$ —	$ —
Other long-term liabilities	(89)	(58)	(35)	(31)
Amounts recognized	$ (91)	$ (60)	$ (35)	$ (31)

The SERP and restoration plans have no plan assets; however, the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP and restoration plans. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $20 million and $16 million as of December 31, 2015 and 2014, respectively. These assets are not included in the plan assets in the above table, but are reflected in other assets on the Consolidated Balance Sheets.

Unrecognized Amounts

The portion of the funded status of the plans net yet recognized in net periodic benefit cost as of December 31 is as follows (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Net loss	$ 248	$ 231	$ 18	$ 18
Prior service credit	(13)	(12)	(12)	(19)
Total	$ 235	$ 219	$ 6	$ (1)

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2015 and 2014 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2013	$ 161	$ 11	$ 172
Net loss arising during the year	59	2	61
Net amortization	(7)	(7)	(14)
Total	52	(5)	47
Balance, December 31, 2014	213	6	219
Net loss arising during the year	31	—	31
Net prior service credit arising during the year	(4)	—	(4)
Net amortization	(11)	—	(11)
Total	16	—	16
Balance, December 31, 2015	$ 229	$ 6	$ 235

	Regulatory Asset (Liability)
Other Postretirement	
Balance, December 31, 2013	$ 12
Net gain arising during the year	(15)
Net amortization	2
Total	(13)
Balance, December 31, 2014	(1)
Net loss arising during the year	1
Net prior service credit arising during the year	3
Net amortization	3
Total	7
Balance, December 31, 2015	$ 6

The net loss and prior service credit that will be amortized in 2016 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Total
Pension	$ 16	$ (3)	$ 13
Other postretirement	—	(3)	(3)
Total	$ 16	$ (6)	$ 10

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit costs were as follows:

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligations as of December 31:				
Discount rate	4.40%	4.00%	4.40%	4.00%
Rate of compensation increase	2.75%	2.75%	2.75%	2.75%
Net periodic benefit cost for the years ended December 31:				
Discount rate	4.00%	4.88%	4.00%	5.00%
Expected return on plan assets	5.60%	5.30%	5.60-6.70%	5.30-6.85%
Rate of compensation increase	2.75%	3.00%	2.75%	3.00%

In establishing its assumption as to the expected return on plan assets, the Company utilizes the asset allocation and return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

	2015	2014
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.70%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2025

A one percentage-point change in assumed health care cost trend rates would have the following effect (in millions):

	One Percentage-Point	
	Increase	Decrease
Total service and interest cost for the year ended December 31, 2015	$ —	$ —
Other postretirement benefit obligation as of December 31, 2015	2	(1)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $22 million and $- million, respectively, during 2016. Funding to the established pension trusts is based upon the actuarially determined costs of the plans and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. The Company considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. The Company's funding policy for its other postretirement benefit plan is to generally contribute an amount equal to the net periodic benefit cost.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2016 through 2020 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2016	$ 54	$ 11
2017	55	10
2018	58	11
2019	55	10
2020	57	10
2021-2025	315	48

Plan Assets

Investment Policy and Asset Allocations

The Company's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by each plan's Pension and Employee Benefits Plans Administrative Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments.

The target allocations (percentage of plan assets) for the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2015:

	Pension	Other Postretirement
	%	%
Debt securities[(1)]	53-77	40
Equity securities[(1)]	23-47	60

(1) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds are allocated based on the underlying investments in debt and equity securities.

Fair Value Measurements

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurement[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents	$ —	$ 5	$ —	$ 5
Debt securities:				
United States government obligations	131	—	—	131
International government obligations	—	4	—	4
Corporate obligations	—	236	—	236
Municipal obligations	—	14	—	14
Agency, asset and mortgage-backed obligations	—	84	—	84
Equity securities:				
United States companies	48	—	—	48
International companies	65	—	—	65
Investment funds[2]	—	181	—	181
Total	$ 244	$ 524	$ —	$ 768

	Input Levels for Fair Value Measurement[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2014				
Cash equivalents	$ 15	$ 22	$ —	$ 37
Debt securities:				
United States government obligations	146	—	—	146
International government obligations	—	11	—	11
Corporate obligations	—	186	—	186
Municipal obligations	—	15	—	15
Agency, asset and mortgage-backed obligations	—	10	—	10
Equity securities:				
United States companies	60	—	—	60
International companies	66	—	—	66
Investment funds[2]	—	310	—	310
Total	$ 287	$ 554	$ —	$ 841

(1) Refer to Note 9 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 83% and 17%, respectively, for 2015 and 66% and 34%, respectively, for 2014. Additionally, these funds are invested in United States and international securities of approximately 72% and 28%, respectively, for 2015 and 81% and 19%, respectively, for 2014.

The following table presents the fair value of plan assets, by major category, for the Company's defined benefit other postretirement plan (in millions):

	Input Levels for Fair Value Measurement[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents	$ 3	$ 1	$ —	$ 4
Debt securities:				
United States government obligations	4	—	—	4
Corporate obligations	—	6	—	6
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	2	—	2
Equity securities:				
United States companies	1	—	—	1
International companies	2	—	—	2
Investment funds[2]	61	27	—	88
Total	$ 71	$ 37	$ —	$ 108

	Input Levels for Fair Value Measurement[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2014				
Cash equivalents	$ 2	$ 1	$ —	$ 3
Debt securities:				
United States government obligations	4	—	—	4
Corporate obligations	—	5	—	5
Municipal obligations	—	1	—	1
Equity securities:				
United States companies	2	—	—	2
International companies	2	—	—	2
Investment funds[2]	62	37	—	99
Total	$ 72	$ 44	$ —	$ 116

(1) Refer to Note 9 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 63% and 37%, respectively, for 2015 and 59% and 41%, respectively, for 2014. Additionally, these funds are invested in United States and international securities of approximately 99% and 1%, respectively, for 2015 and 98% and 2%, respectively, for 2014.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information.

Defined Contribution Plans

The Company's 401(k) plan covers substantially all employees. The Company's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. The Company's contributions to the 401(k) plan were $13 million and $12 million for the years ended December 31, 2015 and 2014, respectively.

(13) Asset Retirement Obligations

The Company estimates its ARO liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. Changes in estimates could occur for a number of reasons, including changes in laws and regulations, 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 generation, 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 $481 million and $528 million as of December 31, 2015 and 2014, respectively.

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

	2015	2014
Waste water remediation	$ 42	$ 53
Evaporative ponds and dry ash landfills	30	27
Asbestos	7	8
Other	16	9
Total asset retirement obligations	$ 95	$ 97

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

	2015	2014
Beginning balance	$ 97	$ 116
Change in estimated costs	3	(24)
Additions	3	—
Retirements	(12)	—
Accretion	4	5
Ending balance	$ 95	$ 97
Reflected as:		
Other current liabilities	$ 13	$ 17
Other long-term liabilities	82	80
	$ 95	$ 97

In 2008, Nevada Power signed an administrative order of consent as owner and operator of Reid Gardner Generating Station Unit Nos. 1, 2 and 3 and as co-owner and operating agent of Unit No. 4. Based on the administrative order of consent, Nevada Power recorded estimated AROs and capital remediation costs. However, actual costs of work under the administrative order of consent may vary significantly once the scope of work is defined and additional site characterization has been completed. In connection with the termination of the co-ownership arrangement, effective October 22, 2013, between Nevada Power and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, Nevada Power and CDWR entered into a cost-sharing agreement that sets forth how the parties will jointly share in costs associated with all investigation, characterization and, if necessary, remedial activities as required under the administrative order of consent. The 2014 change in estimated costs was related to refinement of expected remediation costs at the Reid Gardner Generating Station and impacts of the new coal combustion rule.

Certain of the Company's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, the Nevada Utilities are 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. Management has identified legal obligations to retire generation plant assets specified in land leases for Nevada Power's jointly-owned Navajo Generating Station and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. 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.

The 2015 change in estimated costs is primarily due to changes in the amount and timing of cash flows related to the implementation of the United States Environmental Protection Agency's ("EPA") final rule regulating the management and disposal of coal combustion byproducts resulting from the operation of coal-fueled generating facilities, including requirements for the operation and closure of surface impoundment and ash landfill facilities. The final rule was published in the Federal Register in April 2015 and was effective in October 2015. In addition to impacting existing AROs, the final rule also resulted in the recognition of additional AROs.

(14) Commitments and Contingencies

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.

In June 2013, the Nevada State Legislature passed Senate Bill No. 123 ("SB 123"), which included, in significant part:

- Accelerating the plan to retire 800 MWs of coal plants, starting as soon as December 31, 2014;
- Replacement of such coal plants by issuing requests for proposals for the procurement of 300 MWs from renewable facilities;
- Construction or acquisition and ownership of 50 MWs of electric generating capacity from renewable facilities;
- Construction or acquisition and ownership of 550 MWs of additional electric generating capacity; and
- Assuring regulatory procedures that protect reliability and supply and address financial impacts on customer and utility.

In May 2014, Nevada Power filed its Emissions Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with SB 123. The filing proposed, among other items, the retirement of Reid Gardner Generating Station units 1, 2 and 3 in 2014 and unit 4 in 2017; the elimination of Nevada Power's ownership interest in Navajo Generating Station in 2019; and a plan to replace the generating capacity being retired, as required by SB 123. The ERCR Plan includes the issuance of requests for proposals for 300 MW of renewable energy to be issued between 2014 and 2016; the acquisition of a 272‑MW natural gas co-generating facility in 2014; the acquisition of a 210-MW natural gas peaking facility in 2014; the construction of a 15-MW solar photovoltaic facility expected to be placed in-service in 2015; and the construction of a 200-MW solar photovoltaic facility expected to be placed in-service in 2016. In the second quarter of 2014, Nevada Power executed various contractual agreements to fulfill the proposed ERCR Plan, which are subject to the PUCN approval. The PUCN issued an order dated October 28, 2014 removing the 200‑MW solar photovoltaic facility proposed by Nevada Power from the ERCR Plan but accepting the remaining requests. In November 2014, Nevada Power filed a petition for reconsideration, but in December 2014, the PUCN upheld the original order from October 2014 with respect to material matters. In December 2014, Nevada Power filed its acceptance of the modifications to the ERCR Plan.

In July 2015, Nevada Power filed an amendment to its ERCR Plan with the PUCN. In September 2015, the PUCN approved the filed amendment requesting two renewable power purchase agreements with 100‑MW solar photovoltaic generating facilities related to the replacement of coal plants. Each of these agreements were entered into by issuing requests for proposals for the procurement of energy through the competitive solicitation process that was set forth in Nevada Power's ERCR Plan in compliance with SB 123. In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123. As a result, Nevada Power will not proceed with issuance of a third 100-MW request for proposal for renewable energy until such time as the PUCN determines Nevada Power has satisfactorily demonstrated a need for such electric generating capacity.

Nevada Power - Reid Gardner Generation Station

In October 2011, Nevada Power received a request for information from the EPA Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for Nevada Power's Reid Gardner Generating Station located near Moapa, Nevada. The EPA'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 EPA relating to the plant. Nevada Power completed its responses to the EPA during the first quarter of 2012 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.

Sierra Pacific - Valmy Generation Station

In June 2009, Sierra Pacific received a request for information from the EPA Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for Sierra Pacific's Valmy Generating Station located in Valmy, Nevada. Sierra Pacific co-owns and operates this coal-fueled generating facility. Idaho Power Company owns the remaining 50%. The EPA'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 EPA relating to the plant. Sierra Pacific completed its responses to the EPA 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.

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2015 are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Fuel and capacity contract commitments	$ 818	$ 637	$ 438	$ 416	$ 405	$ 5,027	$ 7,741
Fuel and capacity contract commitments (not commercially operable)	—	20	23	23	30	603	699
Operating leases and easements	17	12	11	10	10	132	192
Maintenance, service, and other contracts	51	120	42	42	40	131	426
Total commitments	$ 886	$ 789	$ 514	$ 491	$ 485	$ 5,893	$ 9,058

Fuel and Capacity Contract Commitments

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 2016 to 2040. 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 2015 and 2014 were $329 million and $313 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

The Company has several long-term contracts for the purchase of coal that expire from 2016 to 2018 and a contract for the transportation of coal that extends through 2017. Additionally, the Company has gas transportation contracts which expire from 2016 to 2046 and gas supply contracts which expire from 2016 to 2017.

Fuel and Capacity Contract Commitments - 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.

Operating Leases and Easements

The Company has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles, and land. These leases generally require the Company to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. The Company also has non-cancelable easements for land. Rent expense on non-cancelable operating leases totaled $20 million and $18 million for the years ended December 31, 2015 and 2014, respectively.

Maintenance, Service and Other Contracts

The Company has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2020 to 2039.

(15) Supplemental Cash Flow Disclosures

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

	2015	2014
Supplemental disclosure of cash flow information -		
Interest paid, net of amounts capitalized	$ 260	$ 268
Supplemental disclosure of non-cash investing and financing transactions:		
Accruals related to property, plant and equipment additions	$ 75	$ 61
Capital and financial lease obligations incurred	$ 8	$ 8

MANAGEMENT'S DISCUSSION AND ANALYSIS
OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of NV Energy, Inc. ("NV Energy"), a holding company that owns Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific") (collectively, the "Nevada Utilities") and certain other subsidiaries (collectively, 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 unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements included elsewhere in this Annual Report. The Company's actual results in the future could differ significantly from the historical results.

Forward-Looking Statements

The Company may make forward-looking statements that involve judgments, assumptions and other uncertainties beyond its control. These forward-looking statements may include, among others, statements concerning revenue and cost trends, cost recovery, cost reduction strategies and anticipated outcomes, pricing strategies, changes in the utility industry, planned capital expenditures, financing needs and availability, statements of the Company's expectations, beliefs, future plans and strategies, anticipated events or trends and similar comments concerning matters that are not historical facts. These types of forward-looking statements are based on current expectations and involve a number of known and unknown risks and uncertainties that could cause the actual results and performance of the Company to differ materially from any expected future results or performance, expressed or implied, by the forward-looking statements. Important factors that could cause actual results to differ materially from those expectations include: market-related effects on revenues and other operating uncertainties, uncertainties relating to economic and political conditions and uncertainties regarding the impact of regulations, changes in government policy and competition. The Company undertakes no obligation to update forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exclusive.

Results of Operations

Net income for the year ended December 31, 2015 was $360 million, an increase of $64 million, or 22% compared to 2014. Net income increased due to lower impairment costs resulting from the settlement of the 2014 general rate case and certain assets not in rates of $39 million, higher margins from increased customer usage due to the impacts of weather and growth of $33 million, lower operating and maintenance of $37 million, lower interest expense of $18 million, recovery of costs associated with advanced service delivery of $12 million and a settlement payment associated with terminated transmission service of $4 million. The increase in net income was offset by higher depreciation and amortization of $31 million primarily due to higher regulatory amortizations and lower interest and dividend income of $8 million.

A comparison of key operating results and discussion of net income follows for the years ended December 31 (dollars in millions):

	2015	2014	Change	
Operating revenue:				
Regulated electric	$ 3,212	$ 3,115	$ 97	3%
Regulated natural gas	137	125	12	10
Nonregulated	2	1	1	100
Total operating revenue	3,351	3,241	110	3
Cost of fuel, energy and capacity	1,458	1,437	21	1
Natural gas purchased for resale	84	76	8	11
Gross margin	$ 1,809	$ 1,728	$ 81	5

Gross margin increased $81 million, or 5% for 2015 compared to 2014 due to:

- $31 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense;
- $17 million due to higher customer usage in 2015, primarily due to the impacts of weather;
- $16 million in higher customer growth in 2015;
- $12 million from recovery of costs associated with advanced service delivery;
- $4 million related to a settlement payment associated with terminated transmission service; and
- $3 million in transmission revenue primarily due to increased ON Line usage.

Operating and maintenance decreased $37 million, or 7% for 2015 compared to 2014 due to $39 million of lower impairment costs resulting from the settlement of the general rate case in 2014 and certain assets not in rates, $19 million of decreased amortizations for demand side management program costs, changes in contingent liabilities, lower compensation costs, a decrease related to the retirement of Reid Gardner Generating Station Units 1-3 and lower costs related to relinquishing an insurance claim in 2014 for a previously sold asset. The decrease was offset by $39 million in ON Line lease expense, $31 million in higher energy efficiency program costs, which are fully recovered in operating revenue and increased planned maintenance costs.

Depreciation and amortization increased $31 million, or 8% for 2015 compared to 2014 due to higher regulatory amortizations as a result of the 2014 general rate case effective January 2015 and the acquisition of Reid Gardner Generating Station Unit 4 in 2014.

Property and other taxes increased $4 million, or 6% for 2015 compared to 2014 due to an increase in property tax assessed values, higher franchise taxes and a new state commerce tax.

Other income (expense) is favorable $14 million, or 6% for 2015 compared to 2014 due to redemption of $250 million Series L, 5.875% General and Refunding Mortgage Notes in January 2015, increased allowance for borrowed and equity funds and higher interest on deferred charges in 2015. The increase was partially offset by lower carrying charges related to the recovery of costs associated with advanced service delivery approved in the filing of the 2014 general rate case effective January 2015.

Income tax expense increased $33 million, or 20% for 2015 compared to 2014. The effective tax rate was 36% in 2015 and 2014.