Regulatory Research Associates
REGULATORY FOCUS

FINAL REPORT March 11, 2014

STATE: NEVADA
COMPANY: Sierra Pacific Power
ACTION: $39.1 million electric rate reduction ordered and $3.9 million gas rate increase authorized[1]

CASE HISTORY

			Millions
6/3/13	Electric and gas base rate changes requested (Subsequently supported $4.7 million electric rate reduction and $6 million gas rate increase)		$(9.4) E 10.2 G
		Total	$0.8
9/26/13	Rate changes recommended by PUC Staff		$(39.3) E 3.7 G
		Total	$(35.6)
12/16/13	PUC votes on issues		--
12/18/13	Final order issued, rate changes ultimately authorized		$(39.1) E[1] 3.9 G[1]
		Total	$(35.2)
12/31/13	Compliance tariff approved (rates effective 1/1/14)	Total	$(35.2)[1]
2/3/14	Order on reconsideration issued		--

	PRESENT CASE		
ELECTRIC OPERATIONS	Supported by Company	Authorized by Commission	Previous Decision 12/20/10
Annual Revenues (millions)	$(4.7)	$(39.1)[1]	$13.1[7]
% of Revenues	(0.7)%	(6.0)%	1.5%
Test Year End	12/31/12[2]	12/31/12[2]	12/31/09
Rate Base Value (millions)	$1,536.2	$1,487.4	$1,580.1
Rate Base (Year-End or Average)	Year-end	Year-end	Year-end
Return on Common Equity	10.7%[3]	10.12%[5]	10.6%[8]
Common Equity % of Capital	46.94%	46.94%	44.11%
Return on Rate Base	8.19%[3]	7.78%[5]	8.06%[8]
GAS OPERATIONS			12/20/10
Annual Revenues (millions)	$6.0	$3.9[1]	$2.7[7]
% of Revenues	4.7%	3.0%	1.7%
Test Year End	12/31/12[2]	12/31/12[2]	12/31/09
Rate Base Value (millions)	$208.6	$191.6	$185.6
Rate Base (Year-End or Average)	Year-end	Year-end	Year-end
Return on Common Equity	10.4%[4]	9.73%[6]	10.1%[9]
Common Equity % of Capital	46.94%	46.94%	44.11%
Return on Rate Base	5.36%[4]	6.04%[6]	5.18%[9]

1 Electric revenue requirement includes incentives of about $3.7 million associated with the Tracy generating facility. The gas rate hike includes about $0.05 million of incentive-related revenue for demand-side management (DSM) programs.
2 Updated through May 31, 2012.
3 Blended returns after incentives for Tracy facility. Without incentives, a 10.4% return on equity (ROE) and an 8.03% overall rate of return (ROR) were sought.
4 Blended returns after incentives for DSM. Without incentives a 10.35% ROE and a 5.34% ROR were sought.
5 Blended returns after incentives for Tracy facility. Without incentives, a 9.8% ROE and a 7.62% overall return were authorized.
6 Blended returns after incentives for DSM. Without incentives a 9.7% ROE and a 6.02% overall return were authorized.
7 Included about $5 million (electric) and about $0.1 million (gas) of incentive-related revenue.
8 Blended returns after incentives. Without incentives, a 10.1% ROE and a 7.86% ROR were authorized.
9 Blended returns after incentives. Without incentives, a 10% ROE and a 5.15% ROR were authorized.

RRA EVALUATION

This Nevada Public Utilities Commission (PUC) decision for NV Energy subsidiary Sierra Pacific Power (SPP) is neutral, on balance, from an investor viewpoint. The PUC adopted base returns on equity (ROEs) for SPP's electric and gas operations that were meaningfully below those adopted in the company's *previous electric and gas rate cases. The base ROE approved for electric operations was slightly below the average of returns authorized electric utilities nationwide in 2013, but the base ROE authorized for gas operations approximates the average authorized gas utilities in 2013. With incentives for the Tracy facility, the blended electric ROE approximates the average authorized electric utilities last year. While the PUC deferred rate recognition of SPP's smart meter investment until the company's next rate filing, other rate base adjustments were modest, and the bulk of Commission's net operating income adjustments were primarily related to depreciation and amortization. Therefore, it appears that the company has been accorded a reasonable opportunity to earn the authorized returns in the first year of new rates. We continue to accord Nevada regulation an Average/2 rating. NV Energy is now a subsidiary of MidAmerican Energy Holdings Company.*

Rate Case Summary

These proceedings were initiated on June 3, 2013, when SPP filed to implement a $9.4 million electric rate reduction and a $10.2 million gas rate increase. The electric filing was tendered in accordance with a state law that requires electric utilities to file general rate cases at least every three years. There is no mandatory rate case filing requirement for gas utilities. For its electric operations, SPP sought a 10.4% return on equity (47.02% of capital) and a 7.74% return on a year-end rate base valued at $1.552 billion for a calendar-2012 test year, updated for known-and-measurable changes through May 31, 2013. For its gas operations, SPP sought a 10.35% return on equity (47.02% of capital) and a 7.72% return on a year-end rate base valued at $204.2 million for a calendar-2012 test year, updated for known-and-measurable changes through May 31, 2013. The proposed rate changes included incentive revenues associated with the Tracy facility and demand-side management (DSM) investments. As calculated by RRA, after consideration of these incentives, the $9.4 million electric rate reduction was based on a 10.74% blended ROE and a 7.9% blended overall return; the $10.2 million gas rate increase was supported by a 10.4% blended ROE and a 7.74% blended overall return.

According to SPP, the proposed electric revenue requirement reduction "reflects a slowing in capital investments to serve customers and reductions in operation and maintenance expense, including administrative and general costs." The gas rate increase was driven by higher debt costs and new investments.

On Aug. 27, 2013, SPP submitted certification filings, in which it supported a $4.7 million electric rate reduction and a $6 million gas rate increase. For its electric operations, SPP sought a 10.4% base ROE and an 8.03% base overall return. For its gas operations, SPP sought a 10.35% base ROE and a 5.34% base overall return. After consideration of the incentives, the $4.7 million electric rate reduction was based on a 10.7% blended ROE and an 8.19% blended overall return; the $6 million gas rate increase was based on a 10.4% blended ROE and a 5.36% blended overall return.

On Sept. 26, 2013, the PUC Staff filed revenue requirement testimony recommending a $39.3 million electric rate reduction and a $3.7 million gas rate increase. For SPP's electric operations, the Staff recommended a 9.6% base return on equity (46.94% of capital) and a 7.53% return on a rate base valued at $1.482 billion. For SPP's gas operations, the Staff recommended a 9.5% base return on equity (46.94% of capital) and a 5.93% return on a rate base valued at $191.9 million. The Staff's proposed rate changes included incentive revenues associated with Tracy and DSM investments, and as calculated by RRA, after consideration of these incentives, the $39.3 million electric rate reduction proposed by Staff was based on a 9.93% blended ROE and a 7.69% blended overall return; the $3.7 million gas rate increase was supported by a 9.55% blended ROE and a 5.95% blended overall return.

On Dec. 11, 2013, the PUC issued a draft decision. On Dec. 18, 2013, the PUC finalized its decision, authorizing SPP a 9.8% base ROE and a 7.62% overall return for the company's electric operations and a 9.7% base ROE and a 6.02% overall return for the company's gas operations. With incentives, the authorized electric return equates to a 10.12% blended equity return; the authorized gas return equates to a 9.73% blended return. No overall revenue requirement was specified.

On Dec. 27, 2013, SPP filed its compliance tariffs, and on Dec. 31, 2013, the PUC approved the company's tariffs. As a result, a $39.1 million electric rate reduction and a $3.9 million gas rate increase became effective Jan. 1, 2014. The authorized rate changes include $3.7 million (electric) and $0.05 million (gas) associated with PUC-approved incentive returns on the Tracy facility and DSM investments, respectively. The table on page 3 summarizes the items accounting for the roughly $34 million difference between the $4.7 million electric rate reduction supported by SPP and the $39.1 million reduction authorized by the PUC.

ELECTRIC RATE CASE DISALLOWANCES (Approximate)

Adjustments Related To:	(Millions)
Rate of Return	$8
Rate Base	5
Net Operating Income	21
Total Adjustments	$34

On Jan. 3, 2014, the Attorney General's Bureau of Consumer Protection (BCP) filed for reconsideration of the PUC's decision with respect to the monthly basic service charge (BSC) established for single-family customers. On Feb. 3, the PUC granted BCP reconsideration and established a BSC of $15.25 for such customers. There was no change in the overall revenue requirement.

Rate of Return

The PUC's adoption of a lower rate of return than that requested by SPP for its electric operations reduced the revenue requirement by about $8 million. For its electric operations, SPP requested a 10.4% base ROE that was calculated utilizing a discounted cash flow (DCF) analysis and capital asset pricing model (CAPM) applied to an electric proxy group of 21 companies. For its gas operations, SPP sought a 10.35% base ROE.

The Staff recommended a 9.6% base ROE for SPP's electric operations, within a "reasonable range" of 9.2% to 9.8% calculated based on two DCF models, the CAPM, and an analysis of historical ROEs. The DCF and CAPM were applied to both the proxy group constructed by SPP and to a proxy group consisting of electric and gas utilities. According to the Staff, SPP's financials have improved since its last rate case in 2010, there are no major projects planned for the next three years, and state regulators have accepted the current historically low interest environment as the new normal, not a temporary phenomenon, and have grated the lowest ROEs in decades. The Staff recommended a 9.5% base ROE for SPP's gas operations, within a reasonable range of 9.1% to 9.7%. The BCP supported a 9.3% base ROE for the company's electric operations, based upon the DCF applied to a proxy group made up of 20 comparable electric utilities. The BCP's electric utility proxy group produced a DCF ROE range of 8.9% to 9.5%. The BCP recommended a 9.2% base ROE for SPP's gas division.

The PUC authorized 9.8% and 9.7% base ROEs for SPP's electric and gas operations, respectively, the upper end of Staff's recommended ROE ranges. The PUC stated that "the ROEs are sufficient for maintaining financial integrity and capital attraction, and providing returns comparable to alternative investments" and "will result in just and reasonable rates." In determining these ROEs, the PUC considered several factors including: SPP's stronger balance sheet compared to the information provided in the last general rate cases, which justified a lower ROE for both the electric and gas divisions than in 2010; SPP's forecasts that it is entering a period of stable earnings and sustained free cash flow; projections that there would be no need to add additional supply-side resources until 2022; SPP's electric division meeting or exceeding its authorized ROR; SPP's credit ratings upgrades in 2013; and, "a supportive regulatory environment."

With respect to capital structure, SPP proposed to utilize its actual capital structure as of May 31, 2013, that included a 46.94% common equity component for the company's electric and gas divisions. The Staff recommended that the PUC adopt SPP's proposed capital structure. The BCP recommended a separate capital structure for SPP's electric and gas divisions. The PUC adopted SPP's proposed capital structure stating that the "Commission has traditionally accepted a common capital structure for the gas and electric divisions."

Initially, SPP proposed a 5.9% cost-of-debt for its electric division and a 0.87% cost of debt for its gas division. In its certification filing, SPP supported a 6.01% cost-of-debt for its electric division and a 0.91% cost of debt for its gas division. The Staff recommended a 5.77% cost of debt for SPP's electric operations and a 2.8% cost of debt for the company's gas operations. On rebuttal, SPP did not oppose Staff's cost of debt recommendations. The PUC adopted Staff's proposed debt costs of 5.77% and 2.8% for the company's electric and gas operations, respectively.

The approved capital structure, in conjunction with the 9.8% base ROE for the company's electric operations, resulted in a 7.62% base overall return. After the incentive for the Tracy facility, we calculate a 10.12% blended ROE and a 7.78% blended overall return. The capital structure and cost rates as calculated by RRA are outlined on the table below.

Type of Capital	Percent of Capitalization	Cost Rate
Long-Term Debt	52.41%	5.77%
Customer Deposits	0.65	0.145
Common Equity	46.94	10.12
	100.00%	7.78%[1]

The approved capital structure, in conjunction with the 9.7% ROE adopted for SPP's gas operations, resulted in a 6.02% overall return. After the incentive for DSM, we calculate a 9.73% blended ROE and a 6.04% blended overall return. The capital structure and cost rates as calculate by RRA are outlined on the table below.

Type of Capital	Percent of Capitalization	Cost Rate
Long-Term Debt	52.41%	2.80%
Customer Deposits	0.65	0.145
Common Equity	46.94	9.73
	100.00%	6.04%

Rate Base

The PUC's adjustments to SPP's supported electric rate base, in aggregate, reduced the company's revenue requirement by about $5 million, on a net basis. The bulk of this difference stemmed from the PUC's decision to deny rate base inclusion of SPP's Advanced Service Delivery Project (ASD). ASD, now referred to as NVEnergize, is a smart meter deployment project being undertaken by NV Energy subsidiaries SPP and Nevada Power Company (NPC). The PUC indicated that the project is not complete and, therefore, it "is impossible for the Commission to determine the full benefits of the ASD Project." The PUC further noted that until SPP provides an analysis into the specific costs and benefits of the project to the electric divisions of NPC and SPP and the gas division of SPP, the projects will not be recognized in rates. The PUC directed SPP to provide additional information on the project in either a combined general rate case with NPC or a companion filing with NPC's 2014 regularly scheduled general rate case filing (whichever is filed first).

Net Operating Income

PUC adjustments to net operating income (NOI), on a net basis, accounted for approximately $21 million of the $34 million electric revenue requirement shortfall in the case. The largest of these adjustments, about $11 million, flowed from the PUC's decisions associated with the theoretical depreciation reserve imbalance (about $5 million) and legacy analog meters (about $6 million). SPP's 2013 depreciation study found that the company had a theoretical reserve surplus of $153.5 million. While SPP recognized that it had a depreciation reserve surplus, the company recommended the continuation of the remaining life technique of determining depreciation rates, and no accelerated amortization of the theoretical reserve surplus. SPP proposed to amortize the cost of its legacy meters over a three-year period. The PUC ordered that 25% of the excess reserve be returned to ratepayers, over a six-year period, after subtracting the impact of using the reserve to offset the regulatory asset for the legacy analog meters. The PUC indicated that it would reassess the six-year amortization timeframe in SPP's next rate case, noting that it "still has concerns about the theoretical reserve imbalance and...if this imbalance is not reduced in a meaningful way by the time [SPP] files its next general rates application, more adjustments may be needed."

SPP proposed to recover about $20 million of costs associated with its indefinitely postponed Emma/Blackhawk transmission project over three years with a return on the unamortized balance. The Staff opined that a portion of the project's costs should be disallowed because in the latter part of 2008, when the gravity of the economic downturn was starting to be realized and the costs were increasing, the need and timing of the project became questionable. The BCP recommended that the costs be recovered over a period no shorter than six years with no return on the unamortized balance. The PUC stated that the "significant cost of the Project justifies a longer amortization period than the three-year period allowed for other regulatory assets....A six-year amortization period mitigates the impact on cost of service. Rate base treatment is warranted given the significant investment...and the extended recovery period for the regulatory asset." This determination reduced the revenue requirement by about $4 million.

An additional $4 million of the electric revenue requirement difference is attributable to the exclusion of depreciation on the disallowed rate base investment associated with ASD (see the Rate Base section above) and disallowance of ASD-related O&M expenses. About $1.5 million of disallowed revenue requirement was associated with SPP's general office building lease. The PUC ordered SPP to establish a regulatory liability associated with the general office building lease savings experienced from Jan. 1, 2011, to Dec. 31, 2013, with such cost savings to be amortized over a three-year period. The PUC noted that "this treatment will result in just and reasonable rates." The PUC adopted various miscellaneous NOI-related adjustments that, in aggregate, reduced the revenue requirement by about $0.5 million.

Rate Design

SPP proposed to increase its monthly single-family residential electric BSC to $15, from $9.25, its fixed monthly multi-family residential BSC to $8, from $6, and its fixed monthly small commercial BSC to

$32, from $24. The Staff recommended that the PUC increase the monthly BSC for single-family residential customers to $13. The Staff did not object to the other BSCs recommended by the company. The BCP recommended that the PUC not increase the residential BSCs, or alternatively, increase them by less than the increase requested by SPP. The PUC adopted monthly BSCs of $17.50 for single family residential, $7.50 for multi-family residential, and $32 for small commercial. The PUC stated that it "continues to support movement toward cost-based rates and the elimination of intra-class subsidies. If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within the class. This is not just and reasonable. It is appropriate to move the BSCs closer to their corresponding cost bases in order to establish appropriate price signals and avoid intra-class subsidies." The PUC also found that the new rates would reduce the subsidy paid by all ratepayers to net metering customers and that the corresponding decrease in the energy component rate was not enough to discourage conservation by residential customers.

On Jan. 3, 2014, the BCP filed for reconsideration of the PUC's decision with respect to the BSC for single-family customers. On Feb. 3, the PUC granted BCP reconsideration and established a BSC of $15.25 for such customers. This change was revenue neutral.

Docket No. 13-06002 (Electric) and Docket No. 13-06003 (Gas)
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