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DRAFT ORDER

Agenda 23-17 / Item No. 3B

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	)	Docket No. 17-06003
Application of Nevada Power Company d/b/a NV Energy for approval of new and revised depreciation and amortization rates for its electric and common accounts.	)	Docket No. 17-06004

At a general session of the Public Utilities Commission of Nevada, held at its offices on December 29, 2017.

PRESENT: JOSEPH C. REYNOLDS, Chairman and Presiding Officer
ANN C. PONGRACZ, Commissioner
BRUCE H. BRESLOW, Commissioner

(PROPOSED ORDER)

ORDER GRANTING IN PART AND DENYING IN PART
GENERAL RATE APPLICATION BY NEVADA POWER COMPANY

EXECUTIVE SUMMARY

Every three (3) years the Public Utilities Commission of Nevada (PUCN) conducts a comprehensive review and financial analysis of Nevada Power Company d/b/a/ NV Energy and the rates charged to Southern Nevada customers. These proceedings commenced on June 5, 2017, and concluded on December 8, 2017. They involved sixteen (16) separate parties represented by legal counsel; eleven (11) days of court-reported legal arguments and fact-based testimony; over 8,000 pages of documents; and the admission of 216 separate exhibits into evidence. The purpose of this review is to ensure that the interests of Southern Nevada ratepayers and those of Nevada Power are reasonably and *fairly balanced* and prudent decisions are being made. Every penny has been counted. Originally, Nevada Power proposed an increase to its rates for the upcoming rate cycle. During the course of these proceedings, Nevada Power amended its proposal. The following Order addresses all of the issues, arguments, and evidence in greater detail. Having thoroughly reviewed the record and applicable law, the General Rate Application filed by Nevada Power is hereby GRANTED IN PART AND DENIED IN PART. Major decisions by the PUCN are summarized below.

RATE DECREASE IS ORDERED FOR SOUTHERN NEVADANS

Electricity rates for most customers of Nevada Power will be decreased by this Order.

The fixed monthly **basic service charge shall be decreased** for single-family residential customers from its current rate of $12.75 per month to a new, lower rate of $12.50 per month. Other rate classes will see a similar reduction in their monthly basic service charges.[1] The monthly **volumetric charge shall also be decreased**. Approximately $30 million dollars cut from Nevada Power's revenue request shall be spread across all residential and commercial customer classes to reduce the per-kilowatt-hour (kWh) charge for electricity consumption. These reductions are projected to cut the average residential family monthly power bill by up to 2 percent. While relatively modest, this reduction is the first of its kind by the PUCN in over 30 years (since 1979).[2]

It is important to note that this rate decrease is occurring while historic levels of Net Energy Metering (NEM) rooftop solar are being installed, the closure and cleanup of coal plants are being accelerated, and new energy laws are being implemented. Voices of Nevadans have been heard.[3]

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[1] These classes are residential single family (RS), multi-family residential (RM), large single family residential (LRS), and small commercial (GS).

[2] These calculations are based upon current rate revenue.

[3] The Presiding Officer held three consumer sessions in Las Vegas where the concerns of Southern Nevada residents regarding their electricity rates and energy issues raised in these proceedings were heard.

This reduction in *both* the fixed and usage-based parts of electric bills will benefit lower-income Nevadans, all-the-while fostering growth in solar energy development and providing an incentive for even greater energy efficiency efforts.

LOWER RATE OF RETURN ON EQUITY

The current return on equity Nevada Power is authorized to earn on its investment is being lowered from 9.8 percent to a **new rate of 9.4 percent**. Evidence presented in these proceedings showed that a return on equity between 9.0 and 9.5 percent fell within a range of reasonableness determined by nearly all the parties. The rate of 9.4 percent is on the higher end of that range. Tens of millions of dollars are being cut by the PUCN from Nevada Power's current revenue request and/or deferred until the next general rate case. Over the following three (3) years, Nevada Power Company will have a total revenue requirement of approximately $1.2 billion dollars.

NEW EARNINGS-SHARING MECHANISM TO CAPTURE OVEREARNINGS

Nevada Power Company will remain financially healthy with a return on equity of 9.4 percent. Future financial benefits that may flow to NV Energy, such as savings through the possible refinancing of its debt at a lower rate in 2018 and 2019 or from the "Tax Cuts and Jobs Act" recently passed by the United States Congress, which proposes reductions in the federal corporate tax rate, are unestablished, but they present a likely opportunity for Nevada Power to realize additional financial savings. To balance and temper the possibility of over-earning by Nevada Power, the PUCN establishes in this Order a first-of-its-kind in Nevada earnings-sharing mechanism between Nevada Power and its customers. Any return on equity received by Nevada Power in excess of 9.7 percent shall be thereafter split equally (50/50) between Nevada Power and ratepayers. This new earnings-sharing mechanism will help rein in any over-earning that may occur.

ACCELERATED CLOSURE OF COAL PLANTS

Nevada Power is making significant progress in accelerating the closure of Nevada's coal-fired generation plants. Senate Bill 123, passed in 2013 by the Nevada State Legislature and signed into law by Governor Brian Sandoval, mandated the closure of Nevada Power's coal-fired power plants. Originally, Navajo Generating Station was scheduled to close in 2025. That date has been moved up to 2019. Reid Gardner Generating Station Units 1-3 were expected to close in 2021. Those were closed in 2014. Reid Gardner Unit 4 was set to close in 2023. That occurred earlier this year in 2017. In this Order, the PUCN aligns the amortization of the costs for the Navajo closure with its new closure date so that future Nevadans will not pay for a power plant after it is no longer in use. The full costs of environmental cleanup and remediation at Reid Gardner are not expected to be known until 2020. Work on the project site is ongoing.

STEADY COURSE FORWARD FOR NEM ROOFTOP SOLAR

Since the PUCN began publically tracking the amount of new rooftop solar capacity installed in Nevada pursuant to Assembly Bill 405, 16.096 megawatts (MW) of new capacity has been applied for by Nevada residents, and 5.075 MW of capacity has actually been installed.[4] This represents thousands of Nevada homes with newly-installed or soon-to-be installed NEM rooftop solar. The current time-of-use rates shall remain open and undisturbed until the issue is adjudicated with input from all stakeholders in Docket No. 17-07026 to ensure that any new time-of-use rates set by the PUCN enhance NEM growth and encourage electric battery storage.

Skepticism regarding the accuracy of the Marginal Cost of Service Study that has been relied upon in the past to project costs and rates continues, especially as innovation and technology change the grid. Concerns regarding that Study, the type of load shapes for NEM customers that should be relied upon, and any impact NEM has on Nevada rates will be addressed by the PUCN in Docket No. 17-07013, which is a newly-opened investigatory docket to determine a methodology for studying NEM in Nevada. It has been said that "[t]o those devoid of imagination, a blank place on the map is a useless waste; to others, the most valuable part." Leopold, Aldo, *A Sand County Almanac and Sketches Here and There*, 176 (Oxford University Press Sp. Ed. 1989). The future of NEM rooftop solar in Nevada is currently a roadmap with blank space—a lot of value and opportunity to build a bright future is there. More information and study of NEM rooftop solar is needed, and that process is ongoing. The regulatory asset previously established for Nevada Power in implementing Assembly Bill 405 shall remain in place.

ADJUSTMENTS FOR NRS CHAPTER 704B EXITING BUSINESSES

Dissatisfaction with the costs associated with exiting from Nevada Power's service pursuant to NRS Chapter 704B remain. This bundled-service-departure process is largely unique to Nevada and, therefore, little in the form of a template exists to follow. Energy prices are often in a state of flux and the future always in motion. It is difficult, if not impossible, to accurately predict future economic conditions. The PUCN is not bound to the views of its prior members, and it will look at these issues anew to ensure that the NRS Chapter 704B process is fair and nondiscriminatory to everyone involved. *See* NRS 704B.310(7)(b)(1). Obtaining fairness of process for *all* means acknowledging and fixing prior errors, so the terms for all departing customers are fair and reasonable, while still accounting for the unique facts of each case.

[4] This information is current as of December 20, 2017.

MGM, Caesars, Switch, and Wynn have paid (or will pay) a combined total of approximately $178 million dollars in upfront impact fees to no longer buy electricity from Nevada Power. It is clear, exiting NRS Chapter 704B customers do not object to paying an impact fee to assist and mitigate any financial harm to remaining Southern Nevada residential ratepayers—they have demonstrated this by already paying enormous amounts of money. Objection and disagreement, however, materialize when it is not clear that those impact fees are benefiting Nevadans and, instead, may go to the benefit and/ or reduce the rates of other businesses. Greater transparency and accountability on how the impact fees are allocated is essential to restoring trust between Nevada Power and the NRS Chapter 704B customers. Irrespective of whether it is occurring as indisputable fact, or is merely a misperception, it remains a problem. The perception of unfairness can be every bit as destructive as true unfairness. Nevada Power shall begin paying carrying charges on all impact fees received.

Liability for non-bypassable charges regarding the closure of Reid Gardner that are a part of the terms of MGM's and Caesar's departures shall be deferred for them (just like all other ratepayers) until Nevada Power's next general rate case in 2020. Because no other ratepayers are being assessed costs regarding coal-fired plant decommissioning assets pursuant to Senate Bill 123, MGM and Caesars shall not pay those either at this time. Their surcharge for net book value **shall also be set at $0 (zero)**. Similarly, any levy of these charges against **Wynn shall also be set at $0 (zero)**, and this issue, as well as any other outstanding NRS Chapter 704B issues, will be adjudicated and re-examined in Wynn's currently-scheduled February 2018 proceedings.

The distribution-only-service rate now being charged by Nevada Power to MGM, Caesars, Wynn, and Switch is the same rate charged to all similarly-situated distribution-only customers, including the Southern Nevada Water Authority. Whether a subsidy that benefits Nevada residential families is unfairly embedded in that rate or the rates of other commercial customers is an issue that warrants closer scrutiny. Ongoing dispute exists about whether there is a subsidy at all. Accordingly, the PUCN is directing for the first time in over 35 years that Nevada Power complete a new and additional cost study for its next general rate case to assist the PUCN in addressing this concern.

NEVADA POWER IS HEALTHY

Nevada Power on the whole has made reasonable and sound business decisions in providing dependable electric service to its customers in Southern Nevada. The costs for which it is seeking recovery have been thoroughly reviewed, and the vast majority are approved by the PUCN as prudent. It is because of the current health of Nevada Power and the electric grid in Nevada that reductions in costs and accelerated progress toward more clean and renewable energy may continue to benefit Southern Nevadans.

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I. INTRODUCTION

Before REYNOLDS, JOSEPH C., Chairman and Presiding Officer.

Nevada law provides that every three (3) years a public utility shall file with the Public Utilities Commission of Nevada (PUCN) a general rate application regarding its costs and any proposed changes to the rates charged to its customers. *See* NRS 704.110. Once filed, the PUCN has a statutorily-imposed deadline of 210 days by which to either approve or disapprove, in whole or part, the proposed changes. NRS 704.110(2).

Here, Nevada Power Company d/b/a NV Energy filed with the PUCN a general rate application, as well as an application to revise depreciation and amortization rates, on June 5, 2017, regarding the electric utility costs and rates for services it provides to its customers throughout southern Nevada. Meanwhile, Assembly Bill 405, which amended Nevada's laws governing Net Energy Metering (NEM), was signed into law and became effective in-part upon being signed, with other provisions becoming effective on August 1, 2017, and September 1, 2017, respectively. Nevada Power's initial filings were amended on September 5, 2017.

Numerous parties intervened in the proceedings and were represented by legal counsel: Vote Solar; Nevada Cogeneration Associates 1 & 2; Wynn Las Vegas; Vivint Solar; Smart Energy Alliance (SEA); Caesars Enterprise Service; Nevadans for Clean Affordable Reliable Energy (NCARE); Sunrun; MGM Resorts International; Southern Nevada Gaming Group; [5] Tesla (formerly Solar City); Walmart Stores and Sam's West; Federal Executive Agencies of the United States (FEA); and Northern Nevada Industrial Electric Users (NNIEU).[6] The Office of the Nevada Attorney General, Bureau of Consumer Protection (BCP),[7] and Regulatory Operations Staff of the PUCN (Staff) also participated.[8]

Based upon an extensive and thorough review of oral and written witness testimony and evidentiary exhibits admitted during eleven (11) days of administrative hearings, and in accordance with Nevada statutes and regulations, the PUCN hereby orders the general rate application filed by

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[5]SNGG includes the following: Boyd Gaming Corporation; Station Casinos; Las Vegas Sands; South Point Hotel, Casino & Spa; Affinity Gaming; Tropicana Las Vegas; LVGV (The M); The Plaza Hotel and Casino; Binions Gambling Hall; and Four Queens Hotel and Casino.

[6] NNIEU includes the following: EP Minerals; Heavenly Valley, Limited Partnership; Sheltie Opco d/b/a Nugget Casino Resort; Nevada Cement Company; Premier Magnesia; Prime Healthcare Services; The Ridge Tahoe Property Owners' Association; Saint Mary's Regional Medical Center; and Renown Health.

[7]The Attorney General intervened pursuant to NRS 228.360.

[8]Staff of the PUCN is automatically a party pursuant to NRS 703.301(1). It is noteworthy that Staff of the PUCN acts independently of the Presiding Officer. *See* NRS 703.301(2).

Nevada Power GRANTED IN PART AND DENIED IN PART.

II. CONSUMER SESSIONS

One original consumer session was held in Las Vegas on September 11, 2017, specifically for the PUCN to hear the comments and concerns of Southern Nevada residents regarding this case. Determining it to be in the public interest, two additional sessions were held in Las Vegas on December 6, 2017.[9] *See* NRS 704.069; NAC 703.164.

III. LEGAL STANDARD OF REVIEW

The filings in this case are made pursuant to the Nevada Revised Statutes (NRS), Chapters 703 and 704, as well as the Nevada Administrative Code (NAC), Chapters 703 and 704.

The PUCN has dual responsibilities. It is responsible for ensuring that any charges imposed on Nevada utility customers are "just and reasonable," *see* NRS 704.001(4); NRS 704.120(1), which is a statutorily-imposed standard consistent with the PUCN's responsibility to "[p]rotect, further and serve the public interest." *See* NRS 703.151(1). Yet, the PUCN is also legally required to balance the public interest with the interest of shareholders of public utilities to ensure that public utilities have "the opportunity to earn a fair return on their investments . . ." NRS 704.001(4). The touchstone of any PUCN proceeding should be achieving fairness and reasonableness in addressing the concerns of both the public *and the utility*. See *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944). Indeed, the United States Supreme Court has stated: "There must be a fair return upon the reasonable value of the property at the time it is being used for the public." *Bluefield Waterworks & Imp. Co v. Public Service Commission of West Virginia*, 262 U.S. 679, 690-91 (1923). However, the Supreme Court has explained that "[t]he ascertainment of that value is not controlled by artificial rules. It is not a matter of formulas, but there must be reasonable judgment having its basis in a proper consideration of all relevant facts." *Id.*

The PUCN has broad authority to fix and remedy rates and charges that are unjust, unreasonable, discriminatory or preferential. *See* NRS 704.120(1). An order by the PUCN will be upheld by a higher court on judicial review when it is "within the legal framework of the law, and based on substantial evidence in the record." *Nevada Power Co. v. Public Utilities Commission of Nevada (PUCN), et al.*, 122 Nev. 821, 834, 138 P.3d 486, 494 (2006) (other internal citations and quotations omitted). Substantial evidence is that which "'a reasonable mind might accept as adequate to support a conclusion.'" *Id.* (quoting *State, Emp. Security v. Hilton Hotels*, 102, 606, 608, 729 P.2d 497, 498 (1986)).

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[9]AARP also filed written comments with the PUCN on September 13, 2017, opposing any rate increase.

Great deference is afforded to the PUCN's "interpretation of its governing statutes or regulations," *see Dutchess Business Service, Inc. v. Nevada State Board of Pharmacy*, 124 Nev. 701, 709, 191 P.3d 1159, 1165 (2008), and a higher court will not "reweigh the evidence" or substitute its judgment on factual questions. *Nevada Power Co.*, 122 Nev. at 495, 138 P.3d at 494; NRS 703.373 (11). Evaluating the credibility of witness testimony and the weight to be given to it resides well-within the province of the PUCN, *i.e.*, fact finder. *See In the Matter of TR v. State*, 119 Nev. 646, 649, 80 P.3d 1276, 1278 (2003). This standard holds true even when expert testimony is conflicting. *See Allen v. State*, 99 Nev. 485, 487-88, 665 P.2d 238 (1983). Indeed, the Nevada Supreme Court has recognized that "[e]xpert testimony is not binding on the trier of fact; [triers of fact] can either accept or reject the testimony as they see fit." *Id.*

The PUCN may also take "[n]otice of judicially cognizable facts and generally recognized technical or scientific facts within the specialized knowledge of the agency," NRS 233B.123(5), and its final decisions "shall be deemed reasonable and lawful" and have operative effect unless they are set aside by a higher court on review upon a showing of clear error or abuse of discretion. *See* NRS 703.373(9) and (11); *see also* NRS 703.374(2). With the above standards of review in mind, the relevant procedural history is discussed below.

IV. RELEVANT PROCEDURAL HISTORY

The past collided with the future while these proceedings were ongoing. In other words, new laws and statutory deadlines through Assembly Bill 405 appeared in this case while old laws and statutory deadlines set forth in NRS Chapter 704 remained in place. Throughout these proceedings, various parties requested to be excused from select phases of the proceedings. All requests were granted by the Presiding Officer. The relevant procedural history of this case is as follows:

•On June 5, 2017, Nevada Power filed a General Rate Application for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers (Docket No. 17-06003). Nevada Power also filed a separate General Rate Application for approval of new and revised depreciation and amortization rates for its electric and common accounts (Docket No. 17-06004).

•On June 12 and June 14, 2017, the General Rate Applications were Publically Noticed.

•On June 15, 2017, Assembly Bill 405 was signed into law by Governor Brian Sandoval.

•On July 21, 2017, a Prehearing Conference was held.

•On July 28, 2017, Nevada Power and Sierra Pacific Power filed a Joint Application in Docket No. 17-07026 to implement its understanding of Assembly Bill 405.

•On September 1, 2017, the PUCN issued an Order in Docket No. 17-07026.

•On September 5, 2017, Nevada Power amended its pending General Rate Applications pursuant to the Order issued by the PUCN in Docket No. 17-07026.

•On September 11, 2017, the PUCN held a Consumer Session in Las Vegas to listen to comments by members of the public regarding the General Rate Applications filed by Nevada Power.

•On September 27, 2017, the amended General Rate Applications were publically re-noticed.

•On September 29, 2017, a second Prehearing Conference was held.

•On October 4, 2017, the Cost of Capital (Phase I) hearing began and was continued until November 1, 2017.

•On November 1, 2017, the continued Cost of Capital (Phase I) hearing occurred.

•On November 13, 2017, the Depreciation (Phase II) hearing occurred.

•On November 14-17, 2017, the Revenue Requirement (Phase III) hearing occurred.

•On December 4-5, 2017, the Rate Design (Phase IV) hearing began and was continued until December 7, 2017.

•On December 6, 2017, the PUCN held two additional Consumer Sessions in Las Vegas to listen to comments by members of the public regarding the amended General Rate Applications filed by Nevada Power.

•On December 7-8, 2017, the continued Rate Design (Phase IV) hearing occurred and the evidence closed thereafter.

This general rate case involves four areas of inquiry and review: Cost of Capital, Depreciation, Revenue Requirement, and Rate Design. Each is discussed below.

V. COST OF CAPITAL

1. The Cost of Capital phase evaluates the opportunity of a public utility to earn a fair return on its investment in providing electric service to customers. Bonbright, James C.; Danielsen, Albert L.; Kamerschen, David R., *Principles of Public Utility Rates,* Public Utilities Reports, Inc., 304-05 (1988). Here, the Cost of Capital hearings were held on October 4, 2017, and November 1, 2017. Seven (7) witnesses testified. Forty-two (42) exhibits and two (2) confidential exhibits were admitted into evidence. Below are the issues, the positions of the parties, and discussion and findings.

A. CAPITAL STRUCTURE

Party Positions

2. Nevada Power reports (as of May 31, 2017) that its capital structure is based on a debt/equity mix of 50.01 percent debt and 49.99 percent equity as shown below:

	Capital Amounts (thousands)	Capital Ratio
Customer Deposits	$77,766	1.44%
Long-Term Debt	$2,632,040	48.58%
Total Debt	$2,709,806	50.01%
Total Equity	$2,708,560	49.99%
Total Capital	$5,418,366	100.00%

(Ex. 24 at 2-3; Ex. 20 at Statement F).

3. MGM contends that a 50/50 capital structure is "a little too thick with equity." Notably, in Nevada Power's general rate case in 2014, equity comprised only 48.18 percent of Nevada Power's capital structure. Moreover, the PUCN approved an equity amount within the last year for Sierra Pacific Power of 48.03 percent. While MGM states that it does not believe a 50/50 debt and equity ratio is an issue that needs to be fixed at this time, MGM cautions against a higher level of equity. (Ex. 35 at 27).

4. BCP makes no changes to Nevada Power's proposed capital structure and recommends the PUCN adopt Nevada Power's capital structure of 50.01 percent debt and 49.99 percent equity. This capital structure recommendation is consistent with Nevada Power's certification update request and the comparable groups. BCP notes that Nevada Power has slightly less financial risk than the comparable group in light of the group's 47 to 48 percent average equity ratio compared to Nevada Power's approximate 50 percent equity ratio. (Ex. 28 at 31-32).

5. Staff takes no issue with Nevada Power's certified capital structure and recommends that the PUCN accept Nevada Power's certified capital structure. (Ex. 31 at 6-7).

Rebuttal

6. Nevada Power argues that, contrary to BCP's assertion, its equity ratio is approximately equal to that allowed for the group of comparable companies. BCP incorrectly relies only on equity ratios as a measurement for financial risk. However, it is irresponsible to evaluate financial risk by only one ratio. Rating agencies analyze multiple ratios and credit factors to determine financial risk. BCP's conclusion that Nevada Power's financial risk is lower is based only on one ratio rather than on the more robust type of analysis performed by the broader financial community. (Ex. 36 at 4-5).

PUCN Discussion and Findings

7. The PUCN finds that Nevada Power's proposed capital structure is reasonable. No party contends otherwise. It is approved.

B. Cost of Debt

Party Positions

8. Nevada Power reports (as of May 21, 2017) a cost of 6.66 percent for long-term debt and a cost of 0.61 percent for customer deposits, which total 6.49 percent for the weighted cost of debt. (Ex. 20 at Statement F).

9. MGM argues that Nevada Power's 6.66 percent cost of long-term debt is not reasonable in comparison with Sierra Pacific's, as Nevada Power's long-term debt interest payments are 275 basis points higher than Sierra Pacific's. This spread is too great to be just and reasonable. MGM calculated the cost of debt for the Regulatory Research Associates (RRA) Electric Utilities relied upon by Nevada Power witness Strunk as industry samples. MGM states that the cost of debt for these utilities is 4.27 percent and argues that Nevada Power's 6.66 percent cost of debt is unprecedented. (Ex. 35 at 19-22).

10. FEA and SEA contend that Nevada Power's cost of debt is overstated because it does not reflect an opportunity to refinance significant amounts of Nevada Power's internal embedded debt securities. Nevada Power has debt securities in 2018 and 2019, the refinancing of which will lower Nevada Power's debt interest expenses. FEA and SEA adjusted Nevada Power's embedded cost of debt down to 6.33 percent to reflect debt issues that Nevada Power can refinance at substantially lower interest rates. FEA and SEA recommend that Nevada Power advise the PUCN on its ability to lock in interest rates for 2018 and 2019. If Nevada Power cannot provide actual locked-in interest rates, the PUCN should award an embedded debt cost of 6.33 percent for 2018. The PUCN should also recognize Nevada Power's savings ability through refinancing to reduce regulatory assets of Nevada Power upon refinancing its debt. (Ex. 27 at 2-3, 22-23).

11. BCP proposes no changes to Nevada Power's cost of debt.[10] (Ex. 28 at 32).

12. Staff recommends acceptance of Nevada Power's cost of debt. (Ex. 31 at 7).

Rebuttal

13. Nevada Power argues that MGM's assertion that Nevada Power's cost of debt is too high when compared to Sierra Pacific is flawed and contrary to positions taken by other witnesses in this case. All of Nevada Power's outstanding debt was outstanding during the last two rate cases. The PUCN accepted a 6.65 percent cost of debt in Nevada Power's general rate case in 2011 (Docket No. 11-06006), which included all of the long-term debt series included in this case. Moreover, MGM fails to account for differences in the debt portfolios of Nevada Power and Sierra Pacific. MGM does not acknowledge or adjust for differences in credit ratings, tenures, issuance dates, or debt structure. (Ex. 36 at 6-8).

14. Nevada Power also states that FEA and SEA's assertions that anticipated savings from refinancing in 2018 and 2019 should be used to lower the allowed Return on Equity (ROE), or to offset early refinancing, should be rejected. Nevada is a historical test period jurisdiction, requiring calculations to look backwards at test periods and certification periods. FEA and SEA seek to circumvent this concept by reaching into a future period for an asymmetrical, single-issue adjustment. This is an inappropriate departure from regulatory principals in this jurisdiction. (Ex. 36 at 10-14).

PUCN Discussion and Findings

15. The PUCN issued a letter on December 6, 2016, pursuant to NRS 704.655, establishing a 0.61 percent interest rate for customer deposits for the period of January 1, 2017, through June 30, 2017. The PUCN finds that Nevada Power's proposed customer deposit rate of 0.61 percent is reasonable and approved.

16. The PUCN also finds reasonable and approves Nevada Power's proposed cost of 6.66 percent for long-term debt. With regard to the proposal by SEA and FEA to use anticipated savings from refinancing in 2018 and 2019 to lower the allowed ROE, the PUCN finds that reaching forward outside of the certification period to capture speculative savings on the cost of debt in 2018 and 2019 is contrary to practice in Nevada. Any adjustment in these proceedings to capture future refinancing cost savings would not qualify for an Expected Change in Circumstance (ECIC) filing under NRS 704.110(4).

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[10] BCP recommends 6.49 percent for the cost of "long-term debt" with a capital ratio of 50.01 percent and a weighted cost of 3.246 percent. While BCP does not specify that these figures pertain to the total cost of debt (long-term debt and customer deposits), the recommendations made by BCP are the same as those made by Nevada Power for the total cost of debt.

C. Return on Equity

Party Positions

17. Nevada Power requests a Return on Equity (ROE) of 10 percent. Nevada Power asserts that this ROE falls at the low end of the zone of reasonableness, considering risk factors specific to Nevada Power. As discussed in further detail below, to compensate for these risks, Nevada Power's cost of equity witness Strunk quantifies a risk premium adjustment of between 0.5 and 1 percent. Strunk recommends that the PUCN apply an additional 0.75 percent to Nevada Power's ROE, particularly if the PUCN issues an ROE below 10 percent.[11] Nevada Power notes that ROE awards in 2016 and 2017 for electric utilities have ranged anywhere from 8.64 percent (for a distribution utility) to 11.6 percent (for a generation facility), with the average state-awarded ROE for the electric industry being 9.77 percent in 2016 and 9.92 percent in 2017. Nevada Power contends that 10 percent is consistent with the range of observed ROE awards in other jurisdictions. (Ex. 26 at 4-5, 51-52, Ex. Strunk Direct-15; Ex. 2 at 6-7; Tr. at 126).

18. In its analysis, Nevada Power relies on a proxy group comprised of 30 comparable companies. Nevada Power identifies companies with similar characteristics to determine its proxy group, including: companies considered to be "electric utilities" by the Value Line Investment Survey; companies with a comparable credit rating; companies with 10 quarters of constant or increasing dividends; companies with a positive five-year growth forecast; companies that have not merged or participated in any extraordinary activity within the past 6 months significant enough to distort Discounted Cash Flow (DCF) inputs; companies that operate in a primarily regulated business; and companies with sufficient data available to perform DCF analysis. (Ex. 26 at 15-17).

19. Nevada Power applies three DCF Cost of Capital models, two Risk Premium models, and one Comparable Earnings model to its proxy group. Nevada Power's DCF proxy group model produces an average ROE of 9.01 percent. Nevada Power's DCF Yield Plus Growth model produces an ROE of 9.09 percent. Nevada Power's applied Federal Energy Regulatory Commission (FERC) DCF model produces an ROE of 10.85 percent. Nevada Power's first Risk Premium model, the Capital Asset Pricing Model (CAPM), produces an average ROE of 7.4 percent. Nevada Power's second Risk Premium model produces an average ROE of 9.85 percent. Nevada Power's Comparable Earnings model produces an average ROE of 9.64 percent for utility peers and 16.49 percent for similar,

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[11] Nevada Power did not include this aspect of Strunk's recommendation in its cost of capital or revenue requirement calculations. (Ex. 2 at 6-7).

unregulated industrial firms. (Ex. 26 at 18-30; Ex. Strunk Direct-2; Ex. Strunk Direct-12; Ex. Strunk-Direct-14).

20. Nevada Power states that it faces unique risks due to uncertainty surrounding the pending Energy Choice Initiative to amend Nevada's Constitution and dismantle Nevada's regulatory structure. This issue will appear again before Nevada voters in 2018 and causes the utility to present higher risk to investors. (Ex. 26 at 31-32). Citing the Value Line Investment Survey and other restructured markets, Nevada Power states that the biggest risks to investors include the potential for unrecoverable costs, including stranded generation costs and Provider of Last Resort (POLR) costs. While stranded costs are generally recoverable, some restructured utilities have been prohibited from recovering stranded costs or faced inadequate stranded cost recovery. Uncertainty regarding possible POLR costs further increases risk. As utilities experience restructuring, stock prices become more volatile, and investors demand a higher return on their investment. (Ex. 26 at 32-41; Tr. at 75-80).

21. Nevada Power's cost of equity witness Strunk proposes that an additional 0.75 percent risk premium be applied to Nevada Power's ROE to compensate for the uncertainty and risks brought on by the Energy Choice Initiative. (Ex. 2 at 6-7; Ex. 26 at 49; Tr. at 75-84, 121-123, 124-126).

22. FEA and SEA recommend an ROE of 9 percent, which is the midpoint of its proposed range of reasonableness of 8.9 to 9.1 percent.[12] This recommendation will fairly compensate Nevada Power for its current market cost of common equity and mitigate Nevada Power's claimed revenue deficiency. Nevada Power's requested ROE of 10 percent overstates a fair and reasonable return for Nevada Power and is not supported by Nevada Power's own analysis. Authorized returns for electric utilities have been steadily declining over the last 10 years and recently-authorized ROEs for electric utilities have declined to about 9.6 percent. A majority of electric utilities were awarded ROEs from 9.5 to 9.7 percent over the last 18 months. (Ex. 27 at 2, 4-5, Ex. Gorman Direct-2).

23. FEA and SEA apply a constant growth DCF model using consensus analysts' growth rate projections, a constant growth rate DCF model using sustainable growth rate estimates, a multi-stage growth DCF model, and a Risk Premium model; and a CAPM to estimate Nevada Power's ROE. These models were applied to the same proxy group developed by Nevada Power.[13] (Ex. 27 at 25-26).

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[12] Although FEA and SEA propose a range of reasonableness of 8.9 to 9.1 percent, they also acknowledge that PUCN often takes a gradual approach to adjusting the ROE and, therefore, recommend an ROE of no more than 9.5 percent. (Tr. at 137-138).

[13] FEA and SEA exclude two companies from Nevada Power's proxy group due to mergers that occurred after Nevada Power's initial ROE study was performed. (Ex. 27 at 26; Ex. 38 at 13).

24. FEA and SEA's DCF model yields an average and median ROE for the proxy group of 8.45 and 8.59 percent, respectively. The sustainable growth DCF model produces a proxy group average and median ROE of 8.08 and 7.55 percent, respectively. The multi-stage DCF model produces an average and median ROE of 7.71 and 7.66 percent, respectively. The Risk Premium model shows a midpoint ROE of 9.1 percent. The CAPM model supports an ROE of 8.9 percent. (Ex. 27 at 31, 34, 42, 49, 54, 55).

25. FEA and SEA state that Nevada Power's own analysis actually supports an ROE of 9 percent. Their proxy group single-stage DCF model and Yield Plus Growth model are comparable to Nevada Power's and produced an ROE of 9.01 and 9.09 percent, respectively. However, Nevada Power's FERC analysis is incorrect because Nevada Power fails to demonstrate the existence of anomalous market conditions in this proceeding to justify a higher ROE, as FERC observed in prior decisions. Moreover, Nevada Power's FERC DCF model is not consistent with FERC. Applying proper growth rates yields an ROE of 8.6 percent. Federal Executive Agencies and SEA's CAPM analyses are reasonably comparable to Nevada Power's, but Nevada Power's risk premium analysis does not attempt to gauge an equity risk premium and ROE for a company with similar investment risk characteristics to Nevada Power. Relying on observable commission findings and a risk premium for utilities of similar risk to Nevada Power indicate a fair ROE for Nevada Power to be around 9.5 percent. Additionally, Nevada Power's Comparable Earnings models are not useful in estimating a fair ROE because Nevada Power failed to demonstrate that its comparable earnings analyses reasonably measure the return requirements investors demand to invest in a company with similar risk as Nevada Power. FEA and SEA's adjustments produce an ROE range of 8.7 to 9.7 percent, as opposed to Nevada Power's range of 7.4 to 16.5 percent. (Ex. 27 at 60-65).

26. FEA and SEA also contend that Strunk failed to prove the reasonableness of his proposed 75-basis-point risk adder. Strunk's assessment was not focused on specific risks to Nevada Power: it was more of an historical review of restructuring concerns for other companies in other jurisdictions. Nevada Power is among the strongest credit-rated electric utility companies in the industry, with a bond rating of "A" with a "Stable" outlook from Standard and Poor's. Standard and Poor's rate Nevada Power as "Strong" due to the fact that it provides essential services to Las Vegas; and has a strong service territory, generally constructive regulatory environment, and geographic diversity—factors which all indicate a relatively stable investment outlook for Nevada Power. Strunk's proposed 75-basis-point risk adder should be rejected. (Ex. 27 at 60, 66).

27. MGM disagrees with Nevada Power's recommended ROE and suggests that a reasonable range is 9 to 9.5 percent based, in part, on analysis of what regulators in other Western states have been

authorizing relative to amounts requested. Nevada Power's own analysis does not support an ROE of 10 percent. Under current conditions, an ROE of 10 percent would almost always be "too rich" and hurt customers. Nevada Power has been over-earning since its last rate case. Nevada Power's actual Returns on Equity exceed the authorized ROE in the last rate case of 9.8 percent by more than 200 basis points and, in the most recent period, by nearly 300 basis points. Persistent over-earning supports selecting an authorized ROE from the lower end of a reasonable range. Nevada Power's consistent and considerable over-earnings warrant a lower authorized return. Regarding Strunk's 0.75 percent risk adder, MGM states that it does not value and interpret the impact fees of NRS 704B customers or consider the virtually assured recovery of all of the costs associated with the earlier-than-planned retirements of Reid Gardner and Navajo power plants. (Ex. 35 at 7-8, 13-16, 16-17; Tr. at 205).

28. BCP recommends an ROE of 9.2 to 9.4 percent. This ROE is consistent with current market capital cost requirements and is more than adequate for the company to maintain its financial integrity and creditworthiness. Nevada Power's requested 10 percent ROE is overstated and is not consistent with just and reasonable rates for consumers given current market capital costs. (Ex. 28 at 3-4; Tr. at 143-144). BCP states that current economic conditions do not warrant higher returns for utility companies and that capital costs remain low in comparison to historical levels. This is conclusion is based upon a review of historical monthly government bond yields, longer-term historical annual 30-year government bond yields, and the historical trend of authorized equity returns set by regulatory authorities around the country. Particularly, 30-year United States Treasury bond yields are under 3 percent and average authorized equity returns for electric utilities have trended downward with other declining capital costs. The continued modest economic growth will cause general investor expectations of growth to continue to be moderate. The bottom line is that the general economic data does not support increasing capital costs. Regulatory authority cost of equity decisions for electric utility operation in 2016 averaged about 9.74 percent for electric utilities. (Ex. 28 at 11, 14).

29. BCP relies upon a Constant Growth DCF method, using four sets of growth rates for the same proxy group companies provided by Nevada Power. BCP estimates the DCF for each company in the proxy group, with results falling in a range of 9.11 to 9.26 percent, with a midpoint at 9.19 percent. BCP also employs a two-stage non-constant growth DCF analysis, which resulted in 9.22 percent. Taken together, BCP's DCF estimates indicate an equity cost midpoint around 9.2 percent for the proxy group. (Ex. 28 at 14-23). BCP also relies upon a CAPM, an ECAPM, and a Risk Premium model of analysis. BCP's CAPM indicates a midpoint ROE of 8.17 percent. BCP's ECAPM indicates a midpoint ROE of 8.54 percent. BCP's Risk Premium model indicates a midpoint ROE of 9.51 percent. (Ex. 28 at 23-28).

30. BCP argues that risk premium methods should be viewed with caution. The CAPM is subject to measurement uncertainties. How to measure the equity risk premium and the time period for which the premium is analyzed are subject to considerable debate. Measures of beta are sometimes unstable from period to period and may not reflect the equity risk spread measure. With these cautions in mind, BCP's risk premium analysis compares the authorized electric utility ROE relative to 30-year United States Treasury bond yields from 1981 to 2016. The risk premium range of results for electric utilities is 9.48 to 9.53 percent, with a midpoint at 9.51 percent. (Ex. 28 at 24-25).

31. Nevada Power's proposed ROE, according to BCP, exceeds current capital market costs in light of low debt costs and current equity returns. It exceeds capital market costs for comparable electric utility companies and Nevada Power's own reasonable equity cost modeling analysis and calculations. It also exceeds the DCF, Yield Plus Growth, CAPM, Comparable Earnings, and Risk Premium estimated ROEs. Instead, these estimates support an ROE range from 9 to 9.4 percent. Nevada Power developed additional estimates to drive its average results upward toward 10 percent. Nevada Power's estimates under its Comparable Earnings approach based on the Dow Jones Industrial Average (DJIA), are not of comparable risk to Nevada Power. Similarly, BCP contends that Nevada Power's review of FERC-authorized ROEs uses electric transmission companies that are not comparable to vertically-integrated electric companies. (Ex. 28 at 36-38).

32. BCP states that Strunk's justification for an additional 0.75 percent increase to the ROE is speculative and unwarranted. The 0.75 percent risk adder would increase revenue requirements by about $28.9 million annually for an event that has yet to occur and may never happen. While Nevada Power faces a potential risk-changing event, Nevada Power's future risk may very well be lower as a result of taking credit-neutral measures if the Energy Choice Initiative is enacted. BCP opposes this risk adjustment. (Ex. 28 at 36, 38-39).

33. Staff recommends that the PUCN adopt an ROE of 9.4 percent, with a reasonable range of 9 to 9.5 percent. Nevada Power's financials have continued to improve since its last rate case in 2014. State regulators are accepting the current historically-low interest environment as a new norm, not a temporary phenomenon, and have granted an average ROE of 9.61 percent for electric utilities in the first half of 2017 and shows ROEs are the lowest granted in decades. (Ex. 31 at 1-4; Tr. at 158-159). Staff applies a Constant Growth DCF model; a Three-Stage DCF model; CAPM; Empirical CAPM (ECAPM); and, an Allowed ROE/Bond Yield model. Staff generally agrees with Nevada Power's screening method and uses the same proxy group in its analysis.

34. Staff notes that Nevada Power's proxy group appears to include much larger companies than Nevada Power in terms of total revenues. Nevertheless, Staff decided not to drop those companies due

to sample size concerns. (Ex. 31 at 2, 7-9). Staff's Constant Growth DCF model calculation produces an average ROE of 8.44 percent. Staff's Three-Stage DCF model produces an average ROE of 8.53 percent. Staff's CAPM and ECAPM produce a mean ROE of 7.83 percent (Staff states that its CAPM and ECAPM results appear to be outliers and that the average ROEs increase to around 9 percent when these ROEs are excluded). Staff's Allowed ROE/Bond Yield model produces an ROE of 9.44 percent. Staff's average over these 5 methods is approximately 8.75 percent. (Ex. 31 at 2, 11, 15, 18, 22).

35. Staff offers two adjustments to Nevada Power's ROE. First, Staff argues that Nevada Power's DCF model should be adjusted. Nevada Power uses a growth rate developed with a sustainable growth model, which requires an analyst to estimate an ROE first to implement the model to estimate a fair ROE. Staff argues that this is a logical inconsistency, and the growth rate produced by this model should therefore be excluded. Removing the sustainable growth rate from Nevada Power's DCF model decreases the ROE from 9.01 to 9 percent and removing it from the FERC DCF model increases the ROE from 10.85 to 11.67 percent. Second, Staff states that Nevada Power includes analysis and data that are not comparable to Nevada Power and therefore should be excluded. More specifically, Nevada Power's Yield-Plus Growth model appears to use industry-level data that likely includes companies Nevada Power screened out of its proxy group because those companies were not similar to Nevada Power. The Yield-Plus Growth model thus produces a result reflecting the industry average—it is not comparable to Nevada Power.

36. Staff contends that Nevada Power does not support its assertion that the DJIA is an appropriate peer group for comparison purposes under its Comparable Earnings model. Staff states that it does not believe any companies in the DJIA are firms similar in risk to Nevada Power. Therefore, the results from Nevada Power's Comparable Earnings model should be discarded. Similarly, the FERC ROE's should also not be relied upon because the firms for which FERC set the ROE do not face similar risks. Nevada Power's data includes ROEs awarded to specific projects that include project-specific risk premiums or incentives different from Nevada Power's. Staff's adjustments for Nevada Power's analysis results in an average ROE of 9.5 percent. (Ex. 31 at 25-30).

37. Staff notes that Nevada Power's ROE request of 10 percent is higher than the 9.8 percent ROE ordered by the PUCN in 2014 and makes no sense because Nevada Power's financial condition has improved since 2014. This suggests that investing in Nevada Power is less risky now than it was in 2014 and, therefore, Nevada Power's ROE should be lower than 9.8 percent. (Ex. 31 at 30; Tr. at 176).

38. Staff argues that a risk premium should not be awarded because Nevada Power's justifications for the risk premium are speculative, the supporting information and analysis is flawed, and no major credit rating agency has downgraded Nevada Power's credit rating or placed Nevada Power on watch.

Strunk's testimony prematurely assumes Nevada Power will be unable to recover stranded costs and will be designated a POLR. Moreover, Strunk's analysis is not representative of restructuring of all states because it uses a small sample for the states and companies that have (successfully and/ or unsuccessfully) restructured. Looking to Nevada's previous experience with restructuring in the late 1990s is also problematic because Nevada's experience with restructuring was greatly affected by the Western Energy Crisis and related market manipulation. While credit rating agencies acknowledge the pending Energy Choice Initiative creates some uncertainty, they have yet to downgrade Nevada Power's credit rating. (Ex. 31 at 30-34; Tr. at 176-178).

Rebuttal

39. Nevada Power argues that the ROEs proposed by FEA, SEA, MGM, BCP, and Staff fall well below those that are available to comparable utilities and, as such, do not reflect a fair return available to investors on investments of comparable risk. FEA and SEA and MGM recommend ROEs so far out of line with the current returns available to public utilities that they "strain credibility." Exhibit Strunk Rebuttal-1 compares Staff, BCP, and Intervener ROE recommendations to returns that have been authorized by other state regulatory commissions for vertically-integrated utilities since January 2016. Exhibit Strunk Rebuttal-1 shows that other commissions granted ROEs ranging from 9.2 to 10.6 percent and confirms that the 9 percent ROE proposed by FEA and SEA fall below the statutory zone of reasonableness. MGM's recommended range of 9 to 9.5 percent also falls outside of the fair returns that have been authorized in other states. While such utilities as Northern States Power and Black Hills were awarded ROEs between 9.2 and 9.4 percent, those situations are not comparable to Nevada Power because they involve a much higher equity ratio. Adjusting for Nevada Power's 50/50 capital structure and risks results in Nevada Power's fair return landing above 9.5 percent. Similarly, BCP's and Staff's recommended ROEs, 9.2 and 9.4 percent, respectively, fall below and at the low end of the returns granted to other regulated electric utilities and are not appropriate for a utility like Nevada Power. None of these recommended ROEs provides the level of return available to other electric utility investments. (Ex. 38 at 5, 11, 12, Exhibit Strunk Rebuttal-1; Tr. at 311-315; Tr. at 377-379).

40. FEA, SEA, MGM, BCP, and Staff do not present any evidence to support their claims that Nevada Power is a low-risk utility relative to the industry in general and relative to the proxy group companies. These positions are largely based on opinion without support from data from the capital markets. Data gathered regarding credit ratings, business and financial risk ratings, proxy group equity ratios, and comparative rankings of other state commissions indicate that Nevada Power is perceived by the investment capital market analysts and regulatory professionals as being of greater risk than the average proxy group company. (Ex. 38 at 12-17; Tr. at 355).

41. Nevada Power argues that BCP, Staff, and the "interveners" fail to fully acknowledge the risks associated with the Energy Choice Initiative. Staff and BCP's position that Energy Choice Initiative risks cannot (and would not) be priced in by investors because the risks have yet to be realized is erroneous and does not align with how investment analysts view Nevada's recent developments. For example, the credit rating agency Fitch has stated that the Energy Choice Initiative creates "a significant measure of uncertainty" for Nevada Power's costs. These uncertainties are why the risk adder to the ROE is appropriate. (Ex. 38 at 18-19, Tr. at 354-355, 375-376).

42. Nevada Power states that Staff and BCP incorrectly use GDP forecast in their DCF models as a proxy for expected long-term earnings because utilities productively grow at rates that exceed overall economic growth. Such reliance will lead to an underestimated ROE. (Ex. 38 at 28-29. Nevada Power also states that Staff's recommended ROE zone of 9 to 9.5 percent is below the average returns available under current regulatory practice. For the years 2015 and 2016, as well as the first 8 months of 2017, the average ROE for comparable utilities ranged from 9.7 to 9.77 percent. (Ex. 38 at 31-32).

43. Staff's adjustments to Nevada Power's DCF model are unwarranted because the adjustments are primarily driven by Staff's intent to exclude industry return benchmarks, as well as benchmarks for unregulated returns. Moreover, claims that Nevada Power has more favorable credit ratings than comparable companies are incorrect. Nevada Power has less favorable credit ratings, and the credit rating agency cited by FEA and SEA also find Nevada Power to be a more risky utility. Additionally, MGM's recommended ROE range of 9 percent to 9.5 percent also falls outside the fair returns. (Ex. 38 at 33-34, 39; Tr. at 311-315).

PUCN Discussion and Findings

44. The PUCN's central task is to establish an ROE that protects and balances the interests of ratepayers and shareholders and fulfills all legal requirements in so doing. Two decisions by the United States Supreme Court have governed the analysis for over a half-century: *Bluefield Water Works and Improvement Company vs. Public Service Commission,* 262 U.S. 679 (1923), and *Federal Power Commission vs. Hope Natural Gas Company,* 320 U.S. 591 (1944). The return should be sufficient for maintaining financial integrity and capital attraction. Indeed, a public utility is entitled to a return equal to that of investments of comparable risks. What constitutes a just and reasonable return "is not a matter of formulas" but the final determination must have "its basis in a proper consideration of all relevant facts." *Bluefield,* 262 U.S. at 690-91.

45. In addition to the relevant law, the PUCN relies on the testimony and evidence presented by expert witnesses by applying the principles of finance, accounting, and economics. This reliance includes both results of the ROE studies of each of the parties and their expert judgment to inform the

PUCN regarding. These include: (1) the state of the economy and the capital markets in which Nevada Power participates; (2) a range of returns necessary for similarly-situated businesses in which investors may invest; and, (3) where Nevada Power fits relative to both Nevada Power's needs to participate in capital markets and how Nevada Power compares to the utilities included in the ROE study. From this process, the PUCN identifies an ROE that satisfies the *Hope* and *Bluefield* standards.

46. Upon consideration of all the relevant evidence, ***the PUCN finds that an ROE of 9.4 percent is reasonable***. This rate appropriately balances the interests of Nevada Power's ratepayers and shareholders, and it results in just and reasonable rates and the opportunity for shareholders to earn a fair return. The voluminous record on this issue demonstrates that an ROE of 9.4 percent will provide a return sufficient for Nevada Power to maintain financial integrity and continue to attract necessary capital investment.

47. ROE recommendations from the parties span from 9 to 10 percent. The parties base their recommendations on current equity market conditions, analyses of the authorized returns of comparable utilities, and the particular circumstances of Nevada Power, such as its capital structure, risk profile, and regulatory environment. It is significant that *all* parties to this case, other than Nevada Power, agree that an ROE between 9.0 and 9.5 percent is within the 'zone of reasonableness.' Notably, an ROE of 9.4 percent is at the high end of that zone.

48. Nevada Power's comparative earnings analysis relies on non-utilities and includes utilities that are not part of the proxy group. Additionally, Nevada Power's use of the FERC DCF method for establishing ROE is not customary in Nevada, and the firms for which FERC set the ROE face different risks than those faced by Nevada Power. Nevada Power offered no credible testimony in support of this approach. Strunk's recommendation for a risk premium of 0.75 percent related to the pending Energy Choice Initiative remains speculative. It is not law.

49. The PUCN finds that Nevada Power's financial position has improved since 2014. Therefore, its new ROE should be lower, not higher, than what was last authorized. Moreover, Nevada Power operates in a supportive regulatory environment, which provides mechanisms for mitigating the effects of regulatory lag and new laws.

D. Weighted Cost of Capital (Rate of Return)

50. Based on Nevada Power's capital structure as of the end of certifications, the cost of debt reported as of that date, and the adopted 9.4 percent ROE, the PUCN hereby sets Nevada Power's weighted cost of capital and overall rate of return at 7.95 percent.[14]

[14] This rate is before the incentive on the Lenzie Generating Station.

	Capital Amount (thousands)	Capital Ratio	Cost of Capital	Weighted Cost Of Capital
Long-Term Debt	$2,632,040	48.58%	6.66%	3.04%
Customer Deposits	$77,766	1.44%	0.61%	0.01%
Total Debt	$2,709,806	50.01%	6.49%	3.25%
Equity	$2,708,560	49.99%	9.40%	4.70%
Total Capital	$5,418,366	100.00%		7.95%

VI. DEPRECIATION

51. Depreciation is "generally defined as decline in, or loss of, value." Bonbright, *Principles of Public Utility Rates,* 268. Here, the Depreciation hearing was held on November 13, 2017. Eleven (11) witnesses testified. Twenty-five (25) exhibits and one (1) confidential exhibit were admitted into evidence. Below are the issues, the positions of the parties, and discussion and findings.

A. Service Life for Transmission, Distribution, and General Plant Accounts

1. Account 303: Software

Party Positions

52. Nevada Power recommends a 12-year Average Service Life (ASL) with an SQ survivor curve, which generates an accrual rate of 7.43 percent. The annual accrual amount based on the actuarial analysis is $19,250,286. (Ex. 44 at 7).

53. BCP recommends an SQ-15 ASL and curve. Nevada Power's use of an SQ-12 curve reflects an estimate that the average service life of its software programs is only 12 years on average. Large enterprise software systems can be customized to specific needs. Other utilities have recognized that their Enterprise Resource Planning (ERP) systems could last 20 years. For example, Florida Power & Light is a utility using ERP systems. That utility just increased the amortization period of its software from 5 to 20 years. A 10-year average life may work for older software, but does not reflect longer service lives of newer systems. (Ex. 52 at. 33-34).

Rebuttal

54. Nevada Power states that BCP's witness David Garrett did not explain what has changed in the past 6 years that would result in a longer life than the 12 years proposed by BCP in a previous depreciation study. A 12-year life is more appropriate and consistent with Nevada Power's expectations for this account's actual assets. Moreover, FP&L's 20-year life for some of its software does not support BCP's 15-year recommendation. Most of FP&L's software applications have a 5-

year life, and, therefore, the overall average life for FP&L's software is closer to being from 10 to 12 years. (Ex. 64 at 58-59).

PUCN Discussion and Findings

55. The PUCN finds that a 12-year ASL and SQ survivor curve for Account 303 is reasonable and consistent with values used by other utilities and Nevada Power's expectations for this account's assets.

2. Account 352: Transmission Structures and Improvements

Party Positions

56. Nevada Power recommends a 60-year ASL with an R3 survivor curve and an accrual rate of 1.20 percent (or $28,982). The statistical analysis continues to support the previously-approved 60-R3 survivor curve. (Ex. 44 at 12, 343).

57. Staff recommends a 65-year ASL with an R3 survivor curve. Staff's recommendation results in a reduction of $3,035.40 in annual depreciation expense. The observed life table and statistical data indicates very few retirements and a service life longer than 65 years. This equipment is associated with either a transmission line or transmission substation, so it is reasonable to set the ASL equal to the 65-year time period that applies to an account that has more robust retirement activity. (Ex. 56 at 28-29).

Rebuttal

58. Nevada Power argues that Staff's proposals for Account 352 appear tied to its views on Account 353 and Account 362 and should be rejected for the same reasons. (Ex. 64 at 42).

PUCN Discussion and Findings

59. The PUCN finds that a 60-year ASL and R3 survivor curve for Account 352 is reasonable. Staff has not provided a compelling basis for increasing this account's ASL.

3. Account 353: Transmission Station Equipment

Party Positions

60. Nevada Power recommends a 60-year ASL with an R2 survivor curve, with an accrual rate of 1.71 percent (or $11,406,942). Newer assets may experience shorter service lives than those installed decades ago because of lower design tolerances. The previously-approved 60-R2 estimate continues to represent a good fit of the data. (Ex. 44 at 12, 344).

61. Staff recommend a 65-year ASL with an R2 survivor curve. Staff's recommendation results in a reduction of $138,923.04 in annual depreciation expense. Staff finds nothing to support Nevada Power's proposal that the previously-approved average life should be retained. Nevada Power did not provide specific documentation to support its claim that newer equipment may to have shorter lives.

The statistical data supports an ASL of 65 to 75 years, and the best-fitting Iowa curves are in the S or L families. (Ex. 56 at 6, 26-28).

Rebuttal

62. Nevada Power contends that Staff's analysis does not fit the data well and notes that Nevada Power's proposed lifespan is not significantly different than the last depreciation study. Nevada Power argues that, if anything, the depreciation study supports that the service life should be shortened. One should review the curve shape beyond the historical data to determine what is most reasonable based on the assets studied. Since the assets in this account include transformers and circuit breakers, for which the probability of retirement tends to increase with age, an R2 curve is a superior estimate to the S and L curves. Nevada Power states that while it has not given significant consideration to the older data points from the original life table, Nevada Power's estimates recognize the retirement at later ages. Staff's estimate ignores these older data points. (Ex. 64 at 21-26).

PUCN Discussion and Findings

63. The PUCN finds that a 60-year ASL and R2 survivor curve for Account 353 is reasonable. Staff failed to justify changing the previously-approved values for this account. Specifically, Staff's statistical analysis for this account relies upon a small level of very old equipment, which may skew its results toward a longer life.

4. Account 354: Transmission Towers and Fixtures

Party Positions

64. Nevada Power recommends a 65-year ASL with an R4 survivor curve, generating an accrual rate of 1.49 percent (or $527,277). The previously-approved estimate is 60-R4. Most of the assets in this account are relatively new. Nevada Power expects towers to have relatively long lives in Nevada Power's dry, low-humidity service territory. A gradual change in service life is most appropriate. (Ex. 44 at12 12, 345).

65. Staff recommends a 65-year ASL and R1 survivor curve. This account's ASL and survivor curve should be the same as or near the recommendation for Account 355. Staff contends that a reduction of $33,696.89 exists in annual depreciation expense. The retirement data for this account is limited and there is no meaningful statistical data. Given the lack of retirement data, it makes sense to tie the curve for Transmission Towers and Fixtures to Account 355. (Ex. 56 at 6, 33).

Rebuttal

66. Nevada Power Nevada Power states that each of Staff's estimated curves are poor fits of the historical data, even when all data points are considered. Nevada Power's estimates generally match the data well for the most meaningful data points. Increases in ASL proposed by Staff are more than

should be expected from this new depreciation study that contains only 6 additional years of data. (Ex. 64 at 30-33).

PUCN Discussion and Findings

67. The PUCN finds that a 65-year ASL and R4 survivor curve for Account 354 is reasonable, and the R4 survivor curve appears to be a better match for the relevant data.

5. Account 355: Transmission Poles and Fixtures

Party Positions

68. Nevada Power recommends a 55-year ASL with an R2 survivor curve, generating an accrual rate of 1.84 percent (or $4,556,594). The previously-approved estimate is 45-R2. The statistical analysis indicates a longer average service life than what was previously approved. Most of the assets in this account are relatively young as 95 percent have been installed within the last 30 years and the statistical indications are not definitive. (Ex. 44 at 12, 346).

69. BCP recommends a 58-year ASL with an R2 survivor curve. Nevada Power's and BCP's Iowa curves have similar shapes and lengths and correctly ignore the "tail" end of the observed life-table curve. However, a 58-R2 curve is a better mathematical fit to the data and a better indication of the future retirement date and remaining life of the assets in this account. (Ex. 52 at 18-20).

70. Staff recommends a 60-year ASL with an R1 survivor curve, resulting in a reduction of $719,907.84 in annual depreciation expense. Nevada Power's repeated statement that "the statistical indications are not definitive" is misplaced. There is other reliable retirement activity upon which to draw judgments on how assets will survive. Notably, Nevada Power built its first long distance transmission lines in 1956 and 1965 and there is still a significant amount of this equipment that survives. When the statistical analysis or this account is examined in total, it indicates an ASL of 65 to 85 years. Nevada Power's proposed ASL is a poor fit when compared to the full observed life table. A 60-R1 ASL and curve is a reasonable recommendation given the previously-approved ASL is 45 years. (Ex. 56 at 6, 30-32).

Rebuttal

71. Nevada Power contends that each of Staff's estimated curves are poor fits of the historical data, even when all data points are considered. Nevada Power's estimates match the data well for the most meaningful data points. Staff's and BCP's proposed increases in ASL are more than should be expected from this new depreciation study that has only 6 additional years of data. Staff's lower mode curve selection for Account 355 extrapolates a lower level of retirements for older ages. This type of retirement pattern is not as typical for transmission line accounts as the patterns for the higher mode curves that Nevada Power recommends. (Ex. 64 at 30-34).

PUCN Discussion and Findings

72. The PUCN finds that a 55-year ASL and R2 survivor curve for Account 355 is reasonable. Staff and BCP have not provided compelling arguments for increasing the ASL more than what Nevada Power proposes. Particularly, Staff's statistical analysis for this account relies upon a small level of very old equipment, which biases its results toward a longer life. BCP's statistical analysis is not materially different from Nevada Power's analysis, and a slightly better-fitting curve does not warrant rejecting Nevada Power's proposed change to this account.

6. Account 356: Transmission Overhead Conductors and Devices

Party Positions

73. Nevada Power recommends a 60-year ASL with an R2 survivor curve, generating an accrual rate of 2.04 percent (or $3,147,788). The previously-approved estimate is 55-R1.5. Most of the assets are relatively young, indicating a longer ASL than the previously-approved estimate. The 60-R2 survivor curve is a good fit of the representative data points. (Ex. 44 at 12, 347).

74. SEA recommends a 65-year ASL with an R2 survivor curve. The original survivor curve data suggests a longer life relative to the smooth survivor curve that Nevada Power proposes. A 65-R2 curve is consistent with the values found by Gannett Fleming in a similar 356 Account for Puget Sound Energy and Portland General Electric Company. (Ex. 49 at 43-44).

75. BCP recommends a 69-year ASL with an R1.5 survivor curve. Nevada Power's proposed curve appears to ignore relevant historical data around age interval 45 and beyond. Nevada Power's curve is too short and leads to overestimated depreciation rates. The 69-R1.5 curve is a better mathematical fit to the observed data and results in a more reasonable depreciation rate for this account. (Ex. 52 at 22-23).

76. Staff recommends a 65-year ASL with an R1 survivor curve, which results in a reduction of $399,738.16 in annual depreciation expense. Nevada Power has not plotted its proposed survivor curve against the full observed life table. Fitting a curve to the full observed life table indicates that the best fit is for an R1.5 curve in the range of 70 years. Vintages greater than 50 years support this conclusion. For example, the line to the Reid Gardner was completed in 1965 and still has 60 percent of plant assets surviving 50 years later. (Ex. 56 at 6, 35).

Rebuttal

77. Nevada Power argues that each of Staff's estimated curves are poor fits of the historical data, even when all data points are considered. Nevada Power's estimates generally match the data well for the most meaningful data points. Staff's and BCP's proposed increases in ASL are more than should be expected from this new depreciation study that has only 6 additional years of data. Staff's lower

mode curve proposal extrapolates a lower level of retirements for older ages. This type of retirement pattern is not typical for transmission line accounts. (Ex. 64 at 30-34).

78. Nevada Power also asserts that SEA's analysis is not consistent with accepted approaches to estimating service lives. Rather than basing recommendations on company-specific information, SEA's recommendations are inappropriately based on estimates Gannet Fleming made for Puget Sound Energy and Portland General Electric. Depreciation studies should instead be based on company-specific information to the extent possible because there are a variety of factors that affect service lives, such as the physical environment, operating policies, accounting policies, and local regulations. (Ex. 64 at 43-45).

PUCN Discussion and Findings

79. The PUCN finds that a 60-year ASL and R2 survivor curve for Account 356 is reasonable. Staff's, BCP's, and SEA's recommendations rely too heavily on a less relevant portion of the survivor curve. Nevada Power's proposed ASL extends the previously-approved ASL by five years, whereas Staff, BCP, and SEA are proposing extensions ranging between 10 and 14 years. Gradual increases in ASL and the survivor curve proposed by Nevada Power are more appropriate.

7. Account 361: Distribution Structures and Improvements

Party Positions

80. Nevada Power recommends a 55-year ASL with an R3 survivor curve, with an accrual rate of 1.81 percent (or $794,708). The previously-approved estimate is 55-R3. Most assets in this account are relatively new. Newer metal and pre-fab structures may have shorter service lives than older masonry structures. Typical estimates in the industry range from 45 to 65 years. (Ex. 44 at 12, 352).

81. Staff recommends a 60-year ASL and R2 survivor curve, which results in a reduction of $93,828.74 in annual depreciation expense. As this equipment is associated with substation equipment, it is reasonable to set the service life and curve near or equal to the service life for Account 362, which has more robust retirement activity and is substation-related. (Ex. 56 at 6, 39, Attachment FWR-3).

Rebuttal

82. Nevada Power argues that Staff's proposals for Account 361 appear tied to Account 353 and Account 362 and should be rejected for the same reasons. (Ex. 64 at 42).

PUCN Discussion and Findings

83. The PUCN finds that a 55-year ASL and an R3 survivor curve for Account 361 is reasonable. Nevada Power and Staff agree that the ASL for this account should increase. However, Nevada Power's proposal of 55 years is more appropriate given the data limitations and the absence of compelling evidence to further extend the ASL.

8. Account 362: Distribution Station Equipment

Party Positions

84. Nevada Power recommends a 60-year ASL with an R3 survivor curve, generating an accrual rate of 1.66 percent (or $8,784,824). The previously-approved estimate is 60-R2.5. This recommendation is a reasonable fit for the historical data, and many assets in this account are relatively young. It would therefore be inappropriate to increase the service life for this account at this time. (Ex. 44 at 12, 353).

85. BCP recommends a 64-year ASL with an R3 survivor curve. Nevada Power's curve is too short, resulting in a higher depreciation rate, and the 64-R3 curve is a better mathematical fit for the observed data. (Ex. 52 at 24).

86. Staff recommends a 65-year ASL with an R2 survivor curve. Staff's recommendation results in a reduction of $1,127,228.43 in annual depreciation expense. The statistical analysis does not support Nevada Power's proposal. Looking at a full-observed life table with Nevada Power's proposal clearly shows Nevada Power's curve has a service life short of what historical data shows. The data shows that an ASL of 70 years or more are appropriate and R curves the best fit. (Ex. 56 at 6, 37-38).

Rebuttal

87. Nevada Power argues that, contrary to Staff's and BCP's discussions, its data does not provide a compelling reason to further increase the service life. Nevada Power's historical data for the current study are similar to the depreciation study conducted in 2011, and the data are not definitive for this account. Moreover, Account 362 has similar equipment to Account 353, so it is reasonable to have the same service lives for these assets. Additionally, the previously-approved 60-year ASL is already relatively long when compared to estimates typically used for other utilities—estimates for most utilities are for ASLs of 60 years or less. The concept of conservatism by Staff witness Maguire applies here. It would be a mistake to increase the relatively long ASL of this account and risk that assets could be retired earlier than expected. (Ex. 64 at 35-36, Allis Rebuttal-1).

PUCN Discussion and Findings

88. The PUCN finds that a 60-year ASL and R3 survivor curve for Account 362 is reasonable. Data alone does not provide a compelling reason to significantly change the ASL and survivor curve. The current ASL estimate is already relatively long compared to other utilities with ASLs of 60 or fewer years. Staff's and BCP's proposed curves are too heavily dependent upon the use of a small amount of historical data (much less than 1 percent). Neither has provided a convincing argument for why this data should be used in the statistical analysis or for significantly changing the ASL and curve.

9. Account 364: Distribution Poles, Towers, and Fixtures

Party Positions

89. Nevada Power recommends a 50-year ASL with an R1 survivor curve, with an accrual rate of 2.94 percent (or $2,068,630). The previously-approved estimate is 50-R1. New growth in Nevada Power's system has typically been served with underground distribution lines since the late 1970s. Damage and deterioration are reasons why poles are retired. (Ex. 44 at 12, 354).

90. Staff recommends a 55-year ASL with an R2 survivor curve, which results in a reduction of $96,235.13 in annual depreciation expense. Nevada Power's recommended curve does not reasonably fit the historical data. Rather, the statistical analysis indicates the best fit is a 61-R0.5 curve. When the full set of observed data is used, it indicates the ASL is 68 years. This, coupled with the fact that most new growth has been served from underground distribution lines for the past 40 years, indicates how this account's assets are surviving. (Ex. 56 at 6, 40).

Rebuttal

91. Nevada Power argues that Staff's survivor curve estimate is a poor fit of the historical data. The previously-approved 50-R1 curve is the same Gannet Fleming recommended in the 2011 depreciation study accepted by the PUCN. (Ex. 64 at 36-37).

PUCN Discussion and Findings

92. The PUCN finds that a 50-year ASL and R1 survivor curve for Account 364 is reasonable. Nevada Power's statistical analysis supports its recommended ASL and curve, and Staff did not provide sufficient reason to change them.

10. Account 365: Distribution Overhead Conductors and Devices

Party Positions

93. Nevada Power recommends a 60-year ASL with an R2 survivor curve and an accrual rate of 2.14 percent (or $2,378,059). Undergrounding, capacity, and damage lead to overhead conductor retirement. (Ex. 44 at 12, 355).

94. Staff recommends increasing the ASL to 65 years with an R1 survivor curve, which results in a reduction of $391,012.27 in annual depreciation expense. Nevada Power plotted a truncated curve and the statistical data does not support the conclusions recommended. Statistical analysis indicates that the best curve is a 93-R0.5 curve. The full set of observed data indicates the ASL is 61 years, which is a very poor fit due to asset retirement in 2008 and 2009. This, coupled with the fact that the new growth has been served from underground lines for the past 40 years, indicates how the assets in this account are surviving. (Exhibit 56 at 6, 42-43).

Rebuttal

95. Nevada Power argues that there is not a clear overall trend in the historical data for this account and, therefore, neither Staff's nor Nevada Power's estimates are a good fit. Staff's forecasts are not consistent with Nevada Power's available experience, and it is inappropriate to extrapolate these long lives based on the available data. Additionally, an ASL of 60 years is already longer than the ASL's estimated for other utilities. (Ex. 64 at 38-39).

PUCN Discussion and Findings

96. The PUCN finds that a 60-year ASL with an R2 survivor curve for Account 365 is reasonable. An ASL of 60 years is already a relatively long life span compared to the ASLs used by most other utilities. Extending the life of these assets any further would be unreasonable. There is not a clear overall trend in the historical data, and that the statistical analysis and curve fitting do not result in a good fit. As a result, less weight has been given to the statistical analysis.

11. Account 366: Distribution Underground Conduit

Party Positions

97. Nevada Power recommends a 55-year ASL with an R3 survivor curve that will generate an accrual rate of 2.04 percent (or $3,436,837). The previously-approved estimate is 60-R4. There has been a higher level of retirement since 2011, and the statistical analysis supports a shorter service life. Conduit has a longer life than cable. Nevada Power used cable-in-conduit (CIC) in the 1990s and 2000s, and when CIC is retired the conduit is also likely retired. (Ex. 44 at 12, 356).

98. BCP recommends a 72-year ASL with an S1 survivor curve. Nevada Power's selected curve initially appears to provide a reasonable fit to the historical data, but a 55-year service life is considerably short compared to other utilities. A 70-year ASL for this account was unopposed in Sierra Pacific Power's last rate case. (Ex. 52 at 25-26).

99. Staff recommends a 65-year ASL with an R2 survivor curve that results in a reduction of $747,919.64 in annual depreciation expense. Nevada Power plotted a truncated curve, and the statistical analysis on the full-observed life table data does not support it. The best fit overall is a 71-S1 curve. When the full set of observed data is used, the analysis indicates the ASL is 82-L1.5. Given that new growth has been served from underground lines for the past 40 years, shows how the assets are likely to survive going forward. (Ex. 56 at 6, 45-46, FWR-17, FWR-3).

Rebuttal

100. Nevada Power argues that the statistical analysis does not provide definitive results and this account's data supports a shorter service life than what was previously approved. Staff's estimate is a poor fit. BCP's and Nevada Power's curves are similar fits to the historical data. Nevada Power's

estimate recognizes the shortening of the service life since the last study, whereas BCP increases the ASL by 12 years. (Ex. 64 at 40-41).

PUCN Discussion and Findings

101. The PUCN finds that retaining the previously-approved 60-year ASL and R4 survivor curve is reasonable. Nevada Power's statistical analysis does not provide definitive results. No party offered a compelling argument for changing the ASL and curve. Reliance on Sierra Pacific Power's service territory for guidance is misplaced in this case.

12. Account 367: Distribution Underground Conductors and Devices

Party Positions

102. Nevada Power recommends a 45-year ASL with an R4 survivor curve that would generate an accrual rate of 2.82 percent (or $37,457,968). The statistical analysis indicates a longer service life than the previously-approved 40-R4 estimate. A cable injection program improved the life expectations for a portion of the older cable. Longer service lives in the data is consistent with the increased use of newer cable installed in conduit. (Ex. 44 at 12, 357).

103. BCP recommends a 54-year ASL with an R3 survivor curve. Nevada Power selected an unreasonably short curve for this account, resulting in an unreasonably high depreciation rate and expense. Nevada Power's curve appears to inappropriately give equal amount of consideration to the data point based on $1.4 billion as it is to the data point based on only 0.0001 percent of that amount. An R3 curve is a better fit for this account when correctly considering the most statistically relevant portions of the observed life table curve. (Ex. 52 at 27-30).

104. Staff recommends a 50-year ASL with an R4 survivor curve and results in a reduction of $5,220,519.78 in annual depreciation expense. This account contains two markedly different technologies—direct buried cable and CIC—with different survivor characteristics for each technology. Vintages older than 37 years have a plant survival rate of 79 percent. Remaining vintages of direct buried cable, *i.e.*, 1979 to 1993, have a plant survival rate of 92 percent. Newer CIC technology has a plant survival rate of 99 percent. Given the evidence, it is reasonable to set the ASL at 50 years with an R4 curve. (Ex. 54 at 6, 47-50, Attachment FWR-18, Attachment FWR-19).

Rebuttal

105. Nevada Power argues that its recommendation is not based on the impact of the cable injection program, and that the program has not had a significant impact on the overall life of the account. Staff's analysis does not provide definitive results. The statistical analysis relied upon by Staff shows a wide range in average service lives and a wide variety of survivor curves as good fits for the data. BCP's approach also focuses on earlier data points and does not produce definitive results.

105A. Given that there is only six additional years of new data, Staff and BCP's estimate changes of 10 years or more are unreasonable. Moreover, older data points support an R4 curve over the R3 curve selected by BCP and the 45-R4 curve is a better fit of the data. (Ex. 64 at 27-30.)

PUCN Discussion and Findings

106. The PUCN finds that a 50-year ASL and R4 survivor curve is reasonable. Statistical analysis and other factors related to the assets in this account support a longer service life. Greater than 95 percent of the assets in this account are CIC, which has been installed in the last 30 years. See Ex. 44 at 104. In this instance, a gradual approach to increasing ASL is appropriate. BCP's proposed 14-year increase of the ASL is excessive given the available statistical data.

13. Account 368: Distribution Line Transformers

Party Positions

107. Nevada Power recommends a 40-year ASL with an R2 survivor curve, generating an accrual rate of 2.91 percent (or $16,619,590). The previously-approved approved estimate is 38-R2. The statistical analysis was smaller to the 2011 study, but the R2 curve remains a good fit. Overhead line transformers typically have a longer service life than underground lines, which are subject to corrosion. Overhead lines are typically replaced due to upgrades and damage, *e.g.*, if hit by a car. (Ex. 44 at 12, 358).

108. SEA recommends a 45-year ASL with an R2 survivor curve. This recommendation is supported by studies performed by Puget Sound Energy and Portland General Electric. The Puget Sound Energy study showed longer service life characteristics of recently installed equipment, in contrast to Nevada Power's depreciation study, supporting a 44-R2 curve. Portland General Electric's study also supported a longer average life, using a 50-R2.5 curve. (Ex. 49 at 46-47).

109. Staff recommends a 40-year ASL and R2 survivor curve. (Ex. 56 at 6).

Rebuttal

110. Nevada Power argues that SEA's analysis is not consistent with accepted approaches to estimating service lives. Rather than basing recommendations on company-specific information, SEA's recommendations are inappropriately based on non-company-specific data, and its proposed 45-R2 survivor curve recommendation is a poor fit of Nevada Power's actual data. (Ex. 64 at 43-45).

PUCN Discussion and Findings

111. The PUCN finds that a 40-year ASL and R2 survivor curve is reasonable. Conventional analysis and techniques, as well as specific data, are the best method for developing recommendations.

14. Account 369: Distribution Services

Party Positions

112. Nevada Power recommends a 50-year ASL with an R4 survivor curve, generating an accrual rate of 2.40 percent (or $4,491,730). The previously-approved estimate is 45-R4. All new services are installed underground, CIC is commonly used, and there have been relatively few retirements for this account. (Ex. 44 at 12, 359).

113. SEA recommends a 55-year ASL with an R4 survivor curve. Nevada Power studied this account's retirements over a 62-year period, during which only a small fraction of plant associated with this account was retired. However, Nevada Power's proposed curve would suggest that only 50 percent of plant in this account would remain surviving after 50 years. Therefore, the original life data indicates a much longer life for plant in Account 369, relative to the depreciation parameters Nevada Power has proposed. A 55-R4 curve conforms to the preference in Nevada of not making an adjustment of more than 10 years in establishing depreciation parameters. (Ex. 49 at 49-50).

114. BCP recommends a 56-year ASL with an R4 survivor curve. The observed life table curve derived from Nevada Power's historical data for this account is not well suited for traditional Iowa Curve-fitting techniques. There is insufficient retirement history in this account such that the observed life table can begin to form a sufficient curve to be fitted. For this reason, BCP selected the 56-R4 curve based on the recent recommendations proposed by utility witnesses. Due to this account's insufficient retirement data, it is instructive to consider the recommended service lives among other utilities to base the recommendation on some objective criteria. (Ex. 52 at 30-31).

115. Staff recommends a 60-year ASL with an R4 survivor curve. Staff's recommendation results in a reduction of $1,089,977.97 in annual depreciation expense. There has been almost no retirement activity in this account. Retirement information in the net salvage statistics indicates Nevada Power retired only 0.1 percent of the account's asset balance at the end of 2016. This indicates a very long service life, and similar accounts, such as Account 362, Account 364, Account 365, and Account 367, have ASLs in the 50 to 65 year range. The statistical analysis for this account indicates the ASL is in the range of 140 years. A 60-year ASL is appropriate. (Ex. 56 at 6, 51-52).

Rebuttal

116. Nevada Power argues that because 95 percent of the assets in this account have not been retired, the statistical analysis does not provide definitive results. Nevertheless, the relatively small level of retirements in the historical data supports a gradual increase in service life. Moreover, Staff and BCP propose service life increases over 10 years. This is inconsistent with prior PUCN orders supporting more gradual increases that are less than 10 years. Additionally, SEA's analysis is inconsistent with

accepted approaches to estimating service life. SEA used non-company-specific data to form its conclusions. (Ex. 45 at 41-45).

PUCN Discussion and Findings

117. The PUCN finds that a 55-year ASL and R4 survivor curve is reasonable. All parties support a longer ASL, and there have been almost no retirements in this account. It is difficult to justify any specific ASL increase based on statistical data. Gradually increasing the ASL is appropriate.

15. Account 372: Leased Property on Customer Premises

Party Positions

118. Nevada Power recommends a 30-year ASL with an R1 survivor curve, with an accrual rate of 4.36 percent (or $5,764,414). There is relatively limited historic data as a result of this being a small account. Nevada Power recommends keeping the previously-approved estimate of 30-R1. (Ex. 44 at 12, 362).

119. SEA recommends a 45-year ASL with an R2 survivor curve. SEA proposes tying the depreciation parameters to Account 368 because many expenditures also relate to transformers. Account 368 should provide a good indication of the life characteristics of the transformers booked. (Ex. 49 at 52-53).

120. Staff recommends a 30-year ASL and R1 survivor curve. (Ex. 5 at 6).

Rebuttal

121. Nevada Power argues that SEA is incorrect in suggesting that much of the expenditures in Account 372 relate to transformers. The assets in this account are light fixtures, night guards, and private area lighting. Accordingly, SEA's proposal to tie the life and net salvage estimates to Account 368 are incorrect. (Ex. 64 at 45).

PUCN Discussion and Findings

122. The PUCN finds that a 30-year ASL and R1 survivor curve is reasonable. No compelling evidence was presented to support a different recommendation.

B. Net Salvage Rates for Infrastructure, Power Plants, and General Accounts

1. Account 356: Transmission Overhead Conductors and Devices

Party Positions

123. Nevada Power recommends a 30 percent net salvage value for this account, which is the previously-approved estimate. The historical data supports maintaining the prior estimate. The overall average cost of removal is 33 percent and the overall overage gross salvage is 3 percent. Together, these percentages average to a net salvage of 30 percent. (Ex. 44 at 347).

124. SEA recommends a 10 percent net salvage value. This account's historical salvage data is sporadic and limited, and the historical data was not rigidly relied on. Rather, Nevada Power proposes to continue using a 30 percent net salvage value based on the parameters that were approved in the prior depreciation study. A lower salvage would better align with the values used by other utilities and is also conceptually more consistent with the nature of the costs associated with removing transmission conductors. There is little expectation that a transmission line will be permanently retired and removed; the individual transmission segments in place today will remain in service for an extended period. Accordingly, the cost of removing an old transmission conductor, to replace it with a new conductor, is the cost that is appropriately allocated to customers using the new conductor, not to current customers. Erring on the side of a lower negative net salvage value of 10 percent for transmission conductor more appropriately allocates the cost of removal to those customers benefiting from the removal, in addition to better corresponding to the values used by other utilities. (Ex. 49 at 44-45).

Rebuttal

125. Nevada Power argues that SEA has failed to base its estimates on Nevada Power data or use accepted methods for estimating net salvage. Instead, SEA inappropriately based its net salvage estimates on estimates of other companies, despite differences between companies. Moreover, SEA's accounting is inconsistent with FERC Uniform System of Accounts (which the PUCN has adopted). Consistent with this practice, the cost of removing or retiring an asset should be the cost of removal. (Ex. 64 at 52-54).

PUCN Discussion and Findings

126. The PUCN finds that a net salvage value of 30 percent is reasonable and consistent with generally-accepted accounting principles.

2. Account 362: Station Equipment

127. Nevada Power recommends a 10 percent net salvage value, which constitutes an increase from the previously-approved 5 percent value. There has been less gross salvage in recent years than in the years prior to 2001. The most recent five-year average net salvage is 46 percent. However, some of the cost of removal recorded in recent years was related to retirements in earlier years. The historical data supports a more negative net salvage estimate. (Ex. 44 at 353). Staff objects to the proposed changes because it is increasing depreciations expense. (Ex. 56 at 7, 54-57, Attachment FWR-20). The PUCN finds that a net salvage value of 10 percent is reasonable for this account.

3. Account 364: Poles, Towers, and Fixtures

128. Nevada Power recommends 45 percent net salvage value, which is an increase from the previously-approved 35-percent value. The historical data indicates that a more negative net salvage estimate is reasonable. The overall average net salvage is 46 percent. Cost of removal recorded in 2015 and 2016 is relatively high compared to previous years. Disposal costs are higher than the past. Other factors, such as work requirements of local authorities, have also increased the costs associated with removing poles. (Ex. 44 at 354). Staff objects to the proposed changes because it is increasing depreciation expense. (Ex. 56 at 7, 54-57, Attachment FWR-20).

129. The PUCN finds that a net salvage value of 45 percent is reasonable for this account.

4. Account 365: Overhead Conductors and Devices

130. Nevada Power recommends a 25-percent net salvage value, which is an increase from the previously-approved 20-percent value. The historical data supports a more negative net salvage estimate. The overall average net salvage is 25 percent, and the most recent 5-year average net salvage is 58 percent. (Ex. 44 at 355). Staff objects to the proposed changes because it is increasing depreciations expenses. (Ex. 56 at 7, 54-57, Attachment FWR-20). However, he PUCN finds that a net salvage value of 25 percent is reasonable for this account.

5. Account 367: Underground Conductors and Devices

131. Nevada Power recommends a 20-percent net salvage value, which is an increase from the previously-approved 15-percent value. Similar to other accounts, the cost of removal recorded in 2015 is relatively high. The overall average net salvage is 19 percent, and the most recent five-year average net salvage is 28 percent. Various factors have resulted in higher removal costs over time. (Ex. 44 at 357). Staff objects to the proposed changes because it is increasing depreciation expense. (Ex. 56 at 7, 54-57, Attachment FWR-20). The PUCN finds that a net salvage value of 20 percent is reasonable for this account.

6. Account 368: Line Transformers

Party Positions

132. Nevada Power recommends a negative 5 percent net salvage value, which is a 20 percent decrease from the previously-approved 15-percent value. Few line transformers are refurbished and reused, so gross salvage has been closer to zero since the 2011 study. The overall average cost of removal is 15 percent, but the five-year average is 34 percent. A negative net salvage estimate is the most appropriate representation of the future expectations for this account. (Ex. 44 at 358).

133. SEA recommends retaining the previously-approved value of 5 percent. (Ex. 49 at 46).

134. Staff recommends adopting a halfway value of 5 percent. While Staff remains concerned with Nevada Power's process change, it is cognizant that it will be 6 years until the next depreciation study is performed. If Nevada Power can better explain process changes in the next study, the net salvage values can be revisited and adjusted accordingly. (Ex. 56 at 58).

Rebuttal

135. Nevada Power argues that the primary basis for Staff's proposed net salvage rates is that it does not believe Nevada Power's recorded data in recent years; Staff provides no other basis for its estimates for most of these accounts. Staff incorrectly included salvage values from prior years in its 2015 to 2016 data, so its results are less meaningful. Nevada Power's data shows that the previously-approved estimates of net salvage value are less negative than the full data set; for this reason, more negative salvage estimates are necessary. (Ex. 50 at 48-50).

136. Nevada Power also disagrees with Staff's assertion that it failed to explain and support process improvements made since 2011. Prior to implementing the process improvements, Nevada Power did not have a formal process for collecting costs of removal and retirement charges. Instead, Nevada Power performed manual reviews, which left room for human error. As a result, Nevada Power implemented retirement and cost of removal process improvements, as well as explained the new process and improved results to Staff through discovery and on-site meetings. Specifically, Nevada Power responded to Staff Data Request 38 with two examples that demonstrate where costs were recorded both before and after the improvements were in place to properly account for how time was spent. The higher levels of costs of removal in recent years are the result of these process improvements. For this reason, the data recorded through 2016 should not only be considered as a reasonable basis for the historical net salvage analysis, but it should also be viewed as the most accurate data. (Ex. 61 at 3-5, 8).

137. In response to SEA's position, Nevada Power states that SEA inappropriately based its negative net salvage estimates on estimates of other companies and did not use Nevada Power-specific data; typically, there are differences between companies. (Ex. 64 at 52).

PUCN Discussion and Findings

138. The PUCN finds that a decrease in the net salvage value to a negative 5 percent is reasonable. Nevada Power witness Fincher appears to have clearly explained the changes to the accounting process for recording net salvage in her rebuttal testimony, and it will be 6 years until the next depreciation study is completed.

139. With regard to Staff's proposed adjustments, the PUCN is concerned that Staff's inquiry into Nevada Power's new accounting process for recording net salvage was not fruitful.

139A. The PUCN's concern is heightened, particularly because it seems that Staff issued appropriate discovery and held meetings specifically to address this new accounting process. Furthermore, Nevada Power appears to provide a clear explanation of its accounting process in its rebuttal testimony. However, to further clarify this accounting process, Nevada Power shall file within 45 days documentation that clearly explains the accounting procedures it uses for recording net salvage. Nevada Power shall offer Staff ample opportunity to address the contents of its filing before it is made. Staff and interested parties, including SEA, are encouraged to examine this compliance filing and propose accounting treatment adjustments should improprieties be discovered in Nevada Power's accounting for net salvage.

7. Account 369: Distribution Services

Party Positions

140. Nevada Power recommends the previously-approved negative 50 percent net salvage estimate. While the actual salvage percent is more negative than the previously-approved estimate, in part due to the level of retirements, the instant recommendation is to continue to use the currently-approved negative 50 percent. (Ex. 44 at 359).

141. SEA recommends reducing the net salvage to 30 percent because this value corresponds to the negative net salvage parameters for Account 369 approved in Portland General Electric Company's recent depreciation study. A zero net salvage value would be reasonable for this account given that under Nevada Power's line extension policies and electric service requirements, the cost burden of removing the service drop lies with the customers. A 30-percent net salvage is likely high because it would not account for payments customers make under Nevada Power's Rule 9. (Ex. 49 at 51).

Rebuttal

142. Nevada Power argues that SEA incorrectly interprets the application of Nevada Power's Rule 9 to this account. Under SEA's interpretation of the rule, the cost burden of removing the service drop lies with the customer, and zero percent net salvage would be reasonable for this account. However, service retirements typically occur as a result of trouble calls; customers would not be responsible for these costs. Rule 9 would therefore not apply. (Ex. 64 at 54).

PUCN Discussion and Findings

143. The PUCN finds that a 50-percent net salvage value for is reasonable. SEA's use of a net salvage value established by Portland General Electric and the application of Rule 9 is misplaced.

8. Account 390: Structures and Improvements

Party Positions

144. Nevada Power recommends a 10-percent net salvage estimate, an increase from the previously-approved -5-percent estimate. There has been more activity in this account in recent years, indicating a higher level of negative net salvage. The most recent 5-year average is 25 percent. Any salvage is likely to be relatively limited for Nevada Power's assets in this account. (Ex. 44 at 367).

145. Staff recommends retaining the previously-approved 5-percent net salvage rate. Nevada Power has not provided any justification for its proposed increase. Nevada Power's sales of past buildings have had a positive value at the end of their useful lives; Nevada Power has not produced any evidence that shows this outcome will not occur in the future. (Ex. 56 at 59-60).

Rebuttal

146. Nevada Power argues that Staff's reasoning for retaining the previously-approved estimate is incorrect. In many cases, buildings will have no value or even negative value once they reach the end of their useful lives. Most of the assets in this account will experience either no salvage or negative net salvage. (Ex. 64 at 51-52).

PUCN Discussion and Findings

147. The PUCN finds that a 10-percent net salvage value is reasonable. Nevada Power's net salvage data for this account reflects an increasingly negative trend, which is inconsistent with Staff's position.

9. Navajo Generating Station Depreciation Accounting Treatment

Party Positions

148. Nevada Power states that it will retire the Navajo Generating Station by the end of 2019, and it proposes to set depreciation rates so that Navajo will be fully depreciated at that time. This results in an increase in electric depreciation expense of $3.5 million, on top of the $13 million in electric depreciation expense without Navajo. (Ex. 47 at 3; Ex. 48 at 12, 21).

149. SEA recommends not increasing the depreciation rate for Navajo in connection with its early retirement. A regulatory asset should be created, as contemplated in the Emissions Reduction and Capacity Replacement (ERCR) plan and in a manner similar to the treatment of the Reid Gardner Generating Station. The regulatory asset, SEA contends, should be amortized over a 6-year period. The impact of this proposal is to reduce rate base by approximately $28,900,000. (Ex. 49 at 19-20, Exhibit Mullins-Direct 6).

150. SNGG disagrees with Nevada Power's position and asserts that current ratepayers should not be forced to pay all of the accelerated costs for early plant retirements that occur as a result of policy initiatives or environmental reasons. The primary reason that future ratepayers should share these costs

is that they are the primary beneficiaries of a cleaner, safer environment. Spreading some of these costs into the future allows for finding ways to offset them with other savings. These savings can result from improved or better technologies, increased operating efficiencies, lower capital costs, load growth, or merely occur with the passage of time.

151. SNGG contends that Nevada Power's approach effectively accepts the previously-approved longer recovery periods for these assets. In Sierra Pacific's 2016 rate case, Docket No. 16-06006, the parties agreed not to accelerate the recovery of the early-retired Valmy Generating Station. Instead of accelerating the recovery of Navajo, these depreciation costs should be placed into a regulatory asset account to be recovered over a future period after the plant fully closes. SNGG recommends accomplishing this by either using previously-approved Navajo depreciation rates for depreciation expense or using the new Navajo depreciation rates proposed in Nevada Power's depreciation study, but proposes to defer any annual difference between the prior rates and the new rates into a regulatory asset account to be collected when the plant closes. (Ex. 50 at 7-15).

152. Staff recommends acceptance of Nevada Power's proposal to set Navajo's depreciation rates, so that Navajo will be fully depreciated by the end of 2019. Yet, Staff also recommends requiring Nevada Power to set up a regulatory liability to capture the over-depreciation that will likely occur as a result of Nevada Power moving up the Navajo retirement date. Nevada Power has computed the depreciation expense for Navajo to collect all of the remaining net book value and estimated cleanup costs by the end of 2019. Because those same depreciation rates are being used to set the revenue requirement and customer rates over a three-year period (from 2018 through 2020), it is highly likely that Nevada Power will collect more in depreciation expense than forecasted to be owed on the Navajo units. Nevada Power could potentially over-collect up to $20 million of depreciation expense for the Navajo units. (Ex. 60 at 9-10; Tr. at 563-565).

Rebuttal

153. Nevada Power argues that SEA is incorrect that its depreciation rates for Navajo are based on an accelerated method of depreciation. Rather, they are based on the straight-line method and match the depreciation rate with the remaining life of the plant. SEA's recommendation is inconsistent with NAC 703.276(1). (Ex. 64 at 56).

PUCN Discussion and Findings

154. The PUCN finds that Nevada Power's proposal to set depreciation rates so that Navajo is fully depreciated by the end of 2019 is both reasonable *and responsible* stewardship for future Nevadans. Nevada Power is not proposing an inappropriately accelerated depreciation method. NAC 703.276(1) provides that "[a]n applicant shall provide a study of depreciation based upon the remaining life of

existing plant at intervals not exceeding 6 years or as otherwise directed . . . ." A 6-year period is consistent with the law. Given that Navajo's remaining life is about two (2) years, it is prudent to set Navajo's depreciation rates in a manner consistent with Nevada Power's depreciation study, thereby fully depreciating the plant over the next two years.

155. It is possible that Nevada Power may over-collect more in depreciation expense due to depreciating Navajo ahead of schedule. Accelerated closure of this coal plant is fully consistent with state policy, let alone good environmental practice. Navajo will be retired in two years—at the end of 2019. Because this case sets rates for the next three years (2018 through 2020), Nevada Power will collect depreciation expenses on Navajo for an extra year. To mitigate any over-collection and protect the interests of ratepayers, Nevada Power shall establish a regulatory liability with carrying charges to capture any over-collection that occurs.

10. Navajo Generating Station Depreciation Interim Retirements

Party Positions

156. Staff recommends rejecting the use of interim survivor curves for Navajo. Staff argues that Nevada Power's proposal to retire the Navajo plant at the end of 2019 unreasonably continues the use of the same historic interim survivor curves for the plant's three units. There should be few retirements and replacements on these three units in the final two years of their lives. Nevada Power's approach implies that the previously-approved retirement and investment schedule for the Navajo units remains unchanged, despite the owners' commitment to retire the plant by the end of 2019. Nevada Power provided Staff with a depreciation analysis with the Navajo interim requirement curves removed, which resulted in a $196,000 reduction in depreciation expenses. (Ex. 60 at 8-9, Attachment PRM-4).

Rebuttal

157. Nevada Power disagrees with Staff. A certain level of interim requirements are expected in order to operate the facility safely and reliably until the end of its life, even if the plant is close to retirement. Nevada Power states that its proposed level of interim requirements are significantly less than in previous years and, therefore, it anticipates a lower level of retirement for the remaining years of Navajo's life. (Ex. 64 at 57-58).

PUCN Discussion and Findings

158. The PUCN does not accept Staff's proposed interim retirement adjustment because a certain level of capital expenditures is likely required to keep Navajo operating reliably until its retirement. Staff and other parties will have an opportunity to examine Nevada Power's capital expenditures for the Navajo project in future rate case proceedings.

11. Nellis Solar II Decommissioning Costs

Party Positions

159. Nevada Power recommends a net salvage rate of 9 percent for the Nellis Solar II plant. (Ex. 44 at 142, 334).

160. Staff states that it does not believe the Nellis Solar II plant decommissioning cost estimate is reasonable. If the size of Nellis Solar PV array was scaled up to the size of Reid Gardner, the decommissioning costs would be similar. It is not plausible that the photovoltaic solar arrays will have similar decommissioning costs as a vintage coal plant. Including $1 million in decommissioning costs is a reasonable starting estimate and provides revenue to perform decommissioning work at the end of the plant's life, even if the site is reused. Staff contends that a $1 million decommission cost and the $46.9 million original cost results in a net salvage rate of 2 percent. (Ex. 60 at 17-19).

Rebuttal

161. Nevada Power disagrees with Staff's estimate of a $1 million decommissioning cost for this plant. Staff's estimate is inconsistent with the lease between Nevada Power and the United States Air Force. Moreover, Nevada Power's estimate is based upon an engineering study completed on a larger solar photovoltaic plant that was scaled down to fit the size of the Nellis. This approach is consistent with how Nevada Power has provided estimates that the PUCN has accepted in the past for gas- and coal-fired units when unit-specific decommissioning studies were unavailable. (Ex. 63 at 6).

PUCN Discussion and Findings

162. The PUCN accepts Nevada Power's proposed net salvage rate for Nellis. Nevada Power's decommissioning cost estimate is supported by a decommissioning study performed by a reputable engineering firm; whereas, Staff's estimate is not supported by a comparable study or any net salvage values used by other utilities. To ensure more thorough information is provided on this matter in the future, Nevada Power is directed to complete an estimate of the decommissioning costs for Nellis based on net salvage values used by other utilities for similar facilities as part of its next depreciation study.

12. Allocation of Cost to Las Vegas Cogeneration Station Units

Party Positions

163. Staff recommends ordering Nevada Power to allocate only 10 percent of the Las Vegas Cogeneration Station acquisition price to LV Cogen unit 1, with the other 90 percent being equally allocated to units 2 and 3. As outlined in the most recent Depreciation Study, Nevada Power allocated the price of the LV Cogen plant equally between units 1, 2, and 3. However, in its ERCR filing, Nevada Power outlined that the majority of the value associated with the LV Cogen acquisitions was attributed to units 2 and 3—the new and larger units. As such, it is inappropriate for Nevada Power to

allocate the bundled acquisition price evenly amongst these three units. A fair allocation would consider such factors as the age, capacity, and efficiency of the units. Accordingly, Nevada Power's allocation of the acquisition price equally across all three units was in error because it overstates the value of the smaller, older, and less efficient LV Cogen unit 1. The impact of this allocation is a decrease of approximately $925,000 to annual depreciation expense. (Ex. 60 at 12-15).

Rebuttal

164. Nevada Power represents that it would be more appropriate to allocate the acquisition costs based on the capacity of the units, as Staff proposes. However, doing so would allocate 18 percent of the costs to unit 1 and the rest equally to unit 2 and unit 3 based on the size of the units. Nevertheless, Nevada Power accepts Staff's recommendation to allocate 10 percent to unit 1 and 45 percent equally to units 2 and 3. (Ex. 63 at 3).

PUCN Discussion and Findings

165. The PUCN finds that Staff's proposed depreciation adjustment is reasonable and it is approved. Reliance upon a cost allocation methodology for LV Cogen for depreciation purposes is inappropriate given the age, capacity, and efficiency of these units.

13. Las Vegas Cogeneration Net Salvage Value

166. Nevada Power filed an errata to its depreciation filing, correcting the LV Cogen decommissioning costs. This correction lowered the annual depreciation expense by $2.18 million. (Ex. 45 at Statement A(1)(a)-(d)). Staff has reviewed Nevada Power's errata and recommends that the PUCN find appropriate Nevada Power's errata correcting the LV Cogen depreciation rates. (Ex. 60 at 12). Given these considerations, the PUCN accepts Nevada Power's LV Cogen net salvage adjustment as described in the errata describing the adjustment.

VII. REVENUE REQUIREMENT

167. The Revenue Requirement phase determines how much revenue, *i.e.*, income and/ or money, the utility is authorized to earn. *See generally* Black's Law Dictionary, 1319 (6d. 1990). Here, the Revenue Requirement hearings were held November 14, 2017, through November 17, 2017. Thirty-nine (39) witnesses testified. Eighty-seven (87) exhibits and six (6) confidential exhibits were admitted into evidence. Below are the issues, positions of the parties, and discussion and findings.

A. NRS Chapter 704B Impact Fees

168. NRS Chapter 704B is unique to Nevada and permits certain customers to choose to no longer purchase electricity from Nevada Power and instead purchase electricity from a "provider of new electric resources." While each applicant may present unique facts that may distinguish it from others, the fundamental duty of the PUCN is to ensure fairness. It is the PUCN's responsibility to ensure that

any departure by a customer from the regulatory compact under NRS Chapter 704B "[w]ill not be contrary to the public interest," *see* NRS 704B.310(5), and that any terms and conditions set by the PUCN are "fair and nondiscriminatory" to the remaining ratepayers of Nevada as well as the departing customer. *See* NRS 704B.310(7)(b)(1).

169. Customers that have 'exited' the regulatory compact pursuant to NRS Chapter 704B include MGM (Docket No. 15-05017), Wynn (Docket No. 15-05006), Switch (Docket No. 16-09023), and Caesars (Docket No. 16-11034). Impact fees[15] assessed to each of these businesses departing from Nevada Power are approximately as follows: MGM ($86.9 million); Wynn ($15.7 million); Switch ($27.0 million); and Caesars ($44.0 million).

1. Amortization of Base Tariff General Rate (BTGR) Impact Fees

Party Positions

170. Nevada Power contends that it began to amortize the Base Tariff General Rate (BTGR) portions of impact fees paid by MGM, Wynn, and Switch on the first month that these customers transitioned to Distribution-Only Service (DOS). (Ex. 115 at 18-19, 23). In accordance with MGM's stipulation in Docket No. 15-05017, Nevada Power reduced MGM's impact fees included in Certification Adjustment Schedule I-CERT-37 to reflect the $16 million impact fee credit. (Ex. 116 at 6; Ex. 70 at 127).

171. MGM is concerned with how its impact fee has been credited by Nevada Power in this case. Nevada Power reduced all of the impact fees already paid in this case by attributing a significant portion of those revenues to its shareholders prior to the date that the new rates from this case will take effect. Nevada Power has done this even though the PUCN has yet to determine when impact fees were to be credited to ratepayers and during a period when Nevada Power was already significantly over-earning. Additionally, Nevada Power "reduced the full amount of the $16 million credit from the impact fee already paid by MGM even though the stipulation [accepted] by the PUCN last summer in Docket No. 15-05017 does not clearly provide for that credit to be used by MGM before 2020." The effect of these two issues, as shown at Schedule I-CERT-37, is a reduction of the balance of general rate revenues to be attributed to ratepayers. (Ex. 118 at 11; Tr. at 1008-1010).

172. SEA recommends that 100 percent of the impact fees paid by departing NRS Chapter 704B customers should be returned to the remaining ratepayers and that no amortization of the balances should be assumed prior to the rate-effective period. (Ex. 49 at 22). SEA provides the following rationale for its recommendation: (1) the funds paid by the departing customers were meant to protect

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[15] These fees do not include any portion to Sierra Pacific Power.

the remaining ratepayers, not Nevada Power; (2) Nevada Power should bear all of the risk associated with the regulatory lag prior to the new rate-effective period; (3) and, customers have already more-than-fully compensated Nevada Power for its cost of service without any need for Nevada Power to retain a portion of the impact fees. (Ex. 49 at 23-25).

Rebuttal

173. Nevada Power argues that the immediate amortization of impact fees is appropriate and that a portion of the impact fees should still accrue to Nevada Power because the NRS Chapter 704B applicants are existing Nevada Power customers. (Ex. 147 at 4). MGM misunderstands the treatment of the $16-million credit provided to MGM. The credit has been moved to a regulatory liability, which will commence earning a carrying charge at Nevada Power's authorized rate of return on January 1, 2018. (Ex. 147 at 5-6).

PUCN Discussion and Findings

174. The PUCN finds that the amortization of the BTGR portion of the impact fees already paid has been properly attributed by Nevada Power to their respective regulatory liability accounts. The BTGR impact fee regulatory liabilities have been amortized consistent with past practice and PUCN Orders, *e.g.*, Docket No. 15-05006 and Docket No. 15-05017. The BTGR impact fees replace the payments that would otherwise have been made by the departing businesses. Prior to a general rate case, the fees are treated as if the customers had not departed bundled retail service at all. During the general rate case, the impact fees are treated as an offset to reduce the revenue requirement for the upcoming rate-effective period. It is a balance between the departing businesses, remaining customers, and the utility. Those offsets are being applied here.

175. The PUCN further finds that Nevada Power has properly accounted for the $16-million credit to MGM's remaining BTGR pursuant to the stipulation accepted in the PUCN's Order in Docket No. 15-05017. Pursuant to the terms of the stipulation, Nevada Power removed the $16-million credit from the MGM BTGR impact fee regulatory liability account and placed it into a separate regulatory liability account. This $16-million credit regulatory liability account begins to accrue interest on January 1, 2018, and exists solely for the benefit of MGM—not the remaining Nevada Power ratepayers. Accordingly, Nevada Power appropriately removed the stipulated $16-million MGM credit from the regulatory liability account that benefits Nevada Power's remaining ratepayers. (Ex. 70 at 127).

2. NRS Chapter 704B Regulatory Liability Carrying Charges on Impact Fees

Party Positions

176. Nevada Power recorded no carrying charges on the general rate portions of the impact fees paid by MGM, Wynn, and Switch after these businesses transitioned to the DOS rate class. (Ex. 3 at 187-88, 290; Ex. 70 at 127).

177. SEA argues that impact fee balances should accrue interest for the benefit of Nevadans for the full period before they are included in rate base. It is appropriate for the NRS Chapter 704B impact fees to be placed in regulatory liability accounts to accrue interest until the impact fees already-paid are reflected in rates. Additionally, SEA contents that Nevada Power's exclusion of carrying charges prior to the next rate-effective period is not consistent with its treatment of regulatory assets. (Ex. 49 at 22, 25-27).

178. BCP states that carrying charges must be calculated on all regulatory liabilities included in cost-of-service development from the time of receipt of revenues in the statutory time period for this general rate case, until such time that the regulatory liabilities are fully-reflected in rate development. If it is reasonable for a utility to earn a "return" on costs deferred within a regulatory asset in the form of a carrying charge upon such deferred costs not yet included in rate development, then it rationally and equitably follows that the utility should calculate a 'negative' carrying charge upon regulatory liabilities that arise between rate cases. Unless carrying charges are calculated on the impact fees from the date of receipt until new rates reflecting the unamortized impact fee as a rate base offset are in effect, Nevada Power will have retained solely for its shareholders the time value of money benefit that Nevada Power has enjoyed from the date of receipt of the impact fee payments until new rates resulting from this docket go into effect in January 2018. (Ex. 65 at 30-32).

179. Staff contends that silence on the issue of mandating carrying charges on the lump-sum payments in final Orders issued in Docket Nos. 15-05006, 15-05017, and 16-09023 does not authorize Nevada Power to exclude such carrying charges. Nevada Power has already received these impact fees, but they will not be reflected in rates, as a reduction to rate base, until new rates go into effect. From the point in time that the lump-sum payments were received by Nevada Power through December 31, 2017, carrying charges should be calculated and included in the balance of these regulatory liabilities. In the current General Rate Application, Nevada Power has included carrying charges on all new regulatory assets requested, excluding the Mohave Generating Station Closure and Decommissioning Regulatory Asset; but, it has excluded carrying charges from each of the five new regulatory liabilities. It is unreasonable and one-sided for Nevada Power to request and receive carrying charges on money it has spent between rate cases and, at the same time, not include carrying charges on revenue or monies Nevada Power has received during the same time period. (Ex. 127 at 4).

180. Staff recommends approval of its calculation of carrying charges and adjustments to related accounts as follows:

> •Wynn: (1) include a carrying charge of $1,116,220, which decreases rate base; (2) increase other revenue by $186,037 to amortize the carrying charge over the applicable six-year amortization period; (3) adjust the Accumulated Deferred Income Taxes (ADIT) by $390,677, which increases rate base;
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> •MGM: (1) include a carrying charge of $5,385,936; (2) increase other revenue by $897,656 to amortize the carrying charge over the applicable six-year amortization period; (3) adjust the ADIT by $1,885,078; and
>
> •Switch: (1) include a carrying charge of $635,161; (2) increase other revenue by $211,720 to amortize the carrying charge over the applicable three-year amortization period; (3) adjust the ADIT by $222,307. (Ex. 127 at 4-5, Attachments KAD 3-5).

Rebuttal

181. Nevada Power states that it has precisely followed the treatment of the NRS Chapter 704B regulatory liabilities as prescribed by PUCN's Orders. (Ex. 142 at 35-36).

PUCN Discussion and Findings

182. The PUCN finds that the purpose of the impact fees paid by departing businesses is not to assist Nevada Power—it is to help the remaining Nevada ratepayers and offset the departing businesses' share of already-made energy investments. The PUCN directs that carrying charges should start accruing on the unamortized BTGR portion of the impact fees paid to Nevada Power going forward to the benefit of ratepayers. Prior PUCN Orders are silent on this issue, but it also has not been raised before the current members of the PUCN. It is fair, and the right thing to do.

3. NRS Chapter 704B Regulatory Liability Amortization Period

Party Positions

183. Nevada Power established regulatory liability accounts for upfront impact fees received from Wynn, MGM, and Switch. Nevada Power began amortizing to revenue the upfront impact fees received from Wynn and MGM over 72 months upon receipt of the payments. Nevada Power proposes to re-amortize over 72 months (two rate cycles) the balances remaining on December 31, 2017, in the impact fees regulatory liability accounts for Wynn and MGM. (Ex. 115 at 18-20).

183A. Nevada Power began amortizing to revenue upfront the impact fee paid by Switch over 36 months. Nevada Power proposes to re-amortize over 36 months the balance of the impact fees remaining in the regulatory liability account for Switch on December 31, 2017. (Ex. 115 at 23).

184. SEA opposes Nevada Power's proposal to re-amortization the impact fees. If amortization of the impact-fee-regulatory liabilities is allowed prior to the next rate-effective period, resetting the amortization period beginning in the next rate-effective period should be rejected. (Ex. 49 at 22). According to SEA, irrespective of when the amortization starts, it should occur over the 3- or 6-year period applicable to the NRS Chapter 704B customer. It is inappropriate for Nevada Power to receive the benefit of amortization prior to the rate-effective period, while also spreading the remaining liability amounts over a longer period of time to further reduce the benefit to ratepayers. It would also be unfair for Nevada Power to retain the $16-million credit negotiated with MGM. (Ex. 49 at 27-31).

Rebuttal

185. Nevada Power contends that SEA does not properly represent the treatment of the $16-million credit provided to MGM. The credit has been moved to a regulatory liability account, which will commence earning a carrying charge at Nevada Power's authorized rate of return on January 1, 2018. (Ex. 147 at 5-6). Nevada Power also contends that the proposed re-amortization periods are appropriate because depreciation and amortization adjustments achieved by extending periods of amortization are not just deferrals that do not harm Nevada Power financially—they help mitigate rates to customers by reducing the impact on the immediate filing. (Ex. 142 at 13).

PUCN Discussion and Findings

186. The PUCN accepts Nevada Power's proposed amortization periods as reasonable. SEA's position will result in the amortization periods ending in the middle of a rate-effective period, which would result in Nevada Power over-crediting ratepayers for the regulatory liability amortization. Nevada Power has requested amortization periods that will synchronize to its next general rate case cycle rate-effective periods to preclude the issue of over-crediting. Moreover, the PUCN finds that modifying the amortization period is a typical approach used for amortizing both regulatory assets and regulatory liabilities to eliminate the effects of any regulatory lag. As previously discussed above in this Order, Nevada Power adequately accounted for the $16-million MGM regulatory liability credit.

4. Application of Impact Fees to the Base Tariff Energy Rate (BTER)

Party Positions

187. Nevada Power did not include for general rate purposes in its filing the Base Tariff Energy Rate (BTER) impact fee assessed to Switch. (Ex. 115 at 23; Ex. 3 at 269).

188. SEA asserts that the Switch BTER regulatory liability balance needs to be included in rate base, even though the amortization occurs in Nevada Power's power cost mechanism. (Ex. 49 at 22). SEA also asserts that the rate base impacts of all of the various components of the Switch regulatory liability need to be reflected as an offset to rate base to ensure that Nevada Power is providing customers with appropriate interest on these revenues. While the prudence of the impact fee allocated to the BTER will be reviewed in the Deferred Energy Account Adjustment (DEAA) proceeding, the rate base impacts are not handled in that proceeding, and, therefore, a separate rate base adjustment needs to be made in this matter. This holds true for the other regulatory liability amounts not reflected in Nevada Power's rate filing, such as the obligation for energy efficiency and renewable energy demonstrations. (Ex. 49 at 31-32).

Rebuttal

189. Nevada Power disagrees with SEA's assertions that Nevada Power has not properly reflected in rate base the portion of Switch's impact fee related to the BTER. Consistent with prior practice, the BTER portion of Switch's impact fee was credited to the deferred energy balancing account in June of 2017. As a result, it reduced the deferred energy account balance at June 30, 2017, which is the basis for the DEAA that became effective on October 1, 2017. Therefore, Nevada Power contends that customers are already enjoying the benefit of that impact fee. (Ex. 147 at 6-8).

PUCN Discussion and Findings

190. The PUCN finds that the BTER portion of Switch's impact fee has already reduced customer rates through the DEAA mechanism and plays no role in the BTGR ratemaking.

B. EMISSIONS REDUCTION AND CAPACITY REPLACEMENT PLAN

1. Reid Gardner Generating Station

a. Regulatory Asset Amortization and Decommissioning Costs

Party Positions

191. Nevada Power seeks to include the regulatory asset containing the net book value of Reid Gardner Units 1-4, as well as the accumulated decommissioning and remediation costs and accrued carrying charges, in rate base. The estimated balance at the end of the certification period is $237.9 million dollars for Reid Gardner units 1-4. Amortization of the Reid Gardner regulatory asset would occur over a 6-year period. (Ex. 70 at 116).

192. The establishment of two separate Reid Gardner regulatory asset accounts was approved in Docket No. 14-05003—one for Reid Gardner Units 1 through 3 and one for Reid Gardner Unit 4. However, Nevada Power maintains that the prior decision to do so anticipated that decommissioning and demolition of the Units would take place at different times. However, Unit 4 is closing ahead of

schedule which made it more cost-effective to complete the decommissioning and demolition activities for the entire plant at the same time. As a result, Nevada Power has been recording decommissioning and demolition costs in a single Reid Gardner regulatory asset account. (Ex. 83 at 10-11).

193. MGM recommends that the initial decommissioning costs already incurred by Nevada Power for Reid Gardner should be deferred until decommissioning is completed. MGM states that deferral is consistent with the manner in which new generation facilities are added into rate base and allows one comprehensive review of the decommissioning and any eventual offset, not only from possible excess earnings; but also from net salvage value, including value of water rights, land, and transmission assets associated with the Reid Gardner site. (Ex. 118 at 5).

194. With regard to its share of Reid Gardner costs pursuant to its NRS Chapter 704B departure, MGM contends that the impact fees already paid by MGM included BTGR revenues at current rates through and beyond the next rate period. If Nevada Power does not require a revenue requirement increase, then the impact fees already paid by MGM are more than adequate to recover Reid Gardner and Navajo costs during the same period. MGM asserts that charging any additional fees to it for Reid Gardner and Navajo costs would be unfair and punitive. (Ex. 118 at 10).

195. SNGG contends that the Reid Gardner decommissioning and remediation costs should be recovered over the lives of the recently-acquired ERCR assets that replaced the Reid Gardner capacity. The remaining average useful life of these plants is 16 years, and the weighted average useful life (based on plant capacity), is 16.8 years. Under a 6-year costs amortization scenario, the rates increase \$39.649 million annually. Under a 16-year amortization, the rates increase \$14.868 million annually—\$24.781 million in savings annually. (Ex. 50 at 16-17). SNGG states that a longer amortization period of decommissioning and remediation costs would more equitably distribute the costs between current ratepayers and future ratepayers who, SNGG maintains, are the primary beneficiaries of the environmental improvements. Additionally, with a longer recovery period for environmental costs, SNGG asserts that more opportunities to offset these costs will arise from improved technologies, increased operating efficiencies, lower capital costs, load growth, and the passage of time. (Ex. 50 at 7, 17).

196. SEA proposes that amortization on decommissioning and remediation of Reid Gardner Units 1-4 be calculated in a way that accounts for sinking carrying charges over the amortization period. This mortgage-style amortization schedule takes into consideration the impact of declining account balances over the amortization period. (Ex. 49 at 2, 7). SEA states that Nevada Power used a straight-line method for developing the amortization expense and the amortization schedule assumes an equal amount of principal reduction in each period. It is calculated by simply dividing the \$237.9 million

regulatory liability account balance by 6 years. SEA maintains that Nevada Power will over-collect under this amortization schedule because, even though the return on the principal amount will decline rapidly after the first year, the total payment for the principal and return is based on the first year of the payment schedule. As a result, Nevada Power will over-collect by approximately $8.248 million in 2020. (Ex. 49 at 14-16). SEA recommends establishing a predefined mortgage-style amortization schedule based on a levelized amount of total repayment in each period, with the amount of principal amortized relatively low in the first year and increasing each year. (Ex. 49 at 17).

197. Staff recommends that the costs for demolition, decommissioning, and remediation for Reid Gardner Units 1-4 be removed from the regulatory asset and that adjudication be deferred until Nevada Power's next general rate case in 2020. Based on Nevada Power's belief that it will not complete its Administrative Order on Consent (AOC) issued by the Nevada Division of Environmental Protection (NDEP) investigation of the Reid Gardner site, complete site restoration activities, and implement NDEP-approved corrective actions until 2021 or 2022; Staff contends that it is more appropriate to address Nevada Power's recovery of the Reid Gardner decommissioning and site remediation costs when the work is finished. Reid Gardner site characterization activities are ongoing, and Nevada Power is still conducting site characterization activities and evaluating the site background conditions to determine characteristics of the site before Reid Gardner was placed into operation.

198. Staff reasons that the costs to decommission and remediate the Reid Gardner site should be reviewed holistically and adjudicated when the demolition, decommissioning, and remediation of the site are substantially complete. Until Nevada Power identifies all of the environmental impacts at the site, the severity of the impact, the specific cause of that impact, and the corrective action required for remediation, Staff states that it is impossible to determine the prudence of the small portion of the demolition, decommissioning, and site remediation costs Nevada Power has incurred to date. (Ex. 138 at 16-22).

Rebuttal

199. Nevada Power opposes Staff's recommendation to defer adjudication of Reid Gardner decommission and remediation regulatory asset account costs. According to Nevada Power, more than 60 percent of the project costs incurred to date have been expended on completed projects. Moreover, Nevada Power states that the rationale to defer is inconsistent with past treatment of similar costs at the Mohave Generating Station. The costs incurred to date on decommissioning and site remediation are prudent expenses that should be included in rate base for recovery in this case. (Ex. 153 at 5, 8).

200. Nevada Power argues further that recovering of Reid Gardner decommissioning and remediation costs now is consistent with NAC 704.9453(6)(b)(3) and (4) and its approved ERCR plan.

Nevada Power has accumulated all costs incurred through the end of the certification period to decommission and remediate Reid Gardner in a regulatory asset. (Ex. 142 at 18).

PUCN Discussion and Findings

201. The PUCN finds that the regulatory asset established for Reid Gardner includes approximately $44 million in decommissioning and remediation costs and approximately $193 million representing net book value. For the reasons set forth in Staff's testimony, the PUCN directs Nevada Power to remove the costs of demolition, decommissioning, and remediation from the Reid Gardner regulatory asset sought for recovery in this case and to establish a new regulatory asset for those costs, including any carrying charges. The costs to decommission and remediate the Reid Gardner site should be reviewed holistically and adjudicated when the decommissioning and remediation of the site is substantially complete at the next general rate case—the work is not over.[16] The job is not done.

202. While the PUCN is not bound by *stare decisis*, it is relevant to note that this approach is consistent with prior determinations with respect to recorded costs for the Ely Energy Center (Docket No. 10-06001, PUCN Order dated December 23, 2010, at 119-120) and the evaluation of the Advanced Service Delivery project costs (Docket No. 13-06002, PUCN Modified Final Order dated February 3, 2014, at 106-109, paragraphs 284-290).

203. The PUCN approves a 6-year amortization of the approximately $193 million representing the net book value of Reid Gardner Units 1-4. The PUCN appreciates the arguments of SNGG to maximize all immediate cost-saving potential to current ratepayers by spreading the costs over a 16-year period and onto future ratepayers; however, the PUCN has a responsibility to achieve balance. Our children and future Nevadans should not have to shoulder the costs of cleaning up the mistakes of prior generations. Ultimately, however, the PUCN disagrees with this approach as reaching too far into the future.

204. Given the deferral of the decommissioning and remediation costs for Reid Gardner and that the net book value amortization is not causing an increase to the BTGR, the PUCN finds that MGM, Caesars, and Wynn shall not be separately assessed any portion of these costs at this time. This matter will be further discussed in the Rate Design portion of this Order.

b. Regulatory Asset Carrying Charges

Party Positions

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[16] Given the PUCN's decisions to defer allocation of the Reid Gardner decommissioning and environmental cleanup costs, issues raised in these proceedings regarding the costs associated with petroleum and evaporation ponds will be addressed at a later date.

205. Nevada Power seeks recovery of carrying charges accrued through the certification date on decommissioning and remediation costs recorded for Reid Gardner Units 1-4 in the amounts of $1.943 and $2.674 million, respectively. (Ex. 70 at 116; Ex. 84 at 2-4).

206. FEA recommends removing from rate recovery the carrying charges associated with Reid Gardner Units 1-4 decommissioning and remediation costs for two reasons. First, Nevada Power has been over-earning during the period in which carrying charges have been incurred. Second, approval of Nevada Power's ERCR plan did not specifically find that customers must pay a return on the decommissioning and remediation deferred costs. (Ex. 117 at 14-15, Attachment Gorman Direct-25).

Rebuttal

207. Nevada Power contends that it has complied with NAC 704.9453(6)(b)(3) and (4) and its previously-approved ERCR plan: Nevada Power has accumulated all costs incurred through the end of the certification period to decommission and remediate Reid Gardner in a regulatory asset. With respect to retirement costs, NAC 704.9453(6) specifically mandates "a carrying charge equal to the currently approved [Allowance for Funds Used During Construction (AFUDC)] rate only on the decommissioning and remediation costs in the regulatory asset or liability account." In Docket No. 14-05003, the PUCN approved Nevada Power's ERCR plan with these instructions. Therefore, Nevada Power requests that the accumulated costs be placed into rate base. (Ex. 142 at 18, 21-22).

PUCN Discussion and Findings

208. The PUCN accepts Nevada Power's calculation of carrying charges on recorded decommissioning and remediation costs of Reid Gardner Units 1-4. NAC 704.9453 eliminates any doubt as to whether Nevada Power is entitled to recovery of the carrying charges associated with the Reid Gardner regulatory asset. It is. The PUCN finds that Nevada Power's calculation comports with the ERCR regulation and ERCR plan accepted that has been previously accepted by the PUCN in consolidated Docket Nos. 14-05003 and 14-06022.

209. FEA's argument that the PUCN should deny Nevada Power recovery of the Reid Gardner carrying charges based on Nevada Power's over-earnings is misplaced because it does not account for Commitment 4 established in the MidAmerican acquisition in Docket No. 13-07021. In that Order, the PUCN stated that "normal rate case rules and procedures" would apply to "costs and revenues, and any under or over earnings would accrue to the Nevada Utilities until the next rate case filings."

210. The PUCN directs Nevada Power to remove the carrying charges from rate base and recovery in this general rate case and place these carrying charges in a regulatory asset with the decommissioning and remediation costs.

c. Regulatory Liability for Non-Labor Operation and Maintenance (O&M) Savings

Party Positions

211. Nevada Power seeks recovery of various costs associated with the retirement of Reid Gardner. (Ex. 3 at I-CERT-30).

212. BCP recommends that a regulatory liability be established to capture the following costs related to Reid Gardner non-labor Operation and Maintenance (O&M) costs for the following: (1) $23.8 million in non-labor O&M savings for the Reid Gardner Units 1-4 that have occurred from Nevada Power's 2014 general rate case through the May 31, 2017, certification date for this case; (2) $2.1 million in carrying charges on the savings identified above through December 31, 2017, the end of the rate-effective date for existing rates; and (3) a $3.9 million dollar reduction to O&M expense representing a 6-year amortization of the regulatory liability. (Ex. 65 at 47-48, Attachment JRD-1, schedule C-9).

213. BCP states that NRS 704.7317 expressly mandates deferred accounting that ensures recovery of all prudently-incurred incremental costs and a return on funds invested to decommission and remediation of Reid Gardner; as well as to acquire, own, and operate replacement capacity. BCP contends that the law provides that customers are responsible for 100 percent of the undepreciated net book value of coal-fired capacity being prematurely retired and O&M costs, depreciation costs, and carrying charges related to the replacement capacity facilities from the date of acquisition to the date that these facilities can be reflected in rates established in the next general rate case. (Ex. 65 at 1-2).

214. BCP states that all four Reid Gardner generating units were operating when rates were established in Docket No. 14-05004. All required O&M expenses for all four Reid Gardner units were included for rate recovery in that prior docket. Since rates were established in Docket No. 14-05004, all four Reid Gardner units have been retired and replaced by 567 megawatts of renewable energy and other non-coal-fired capacity. Regulatory assets have been established to capture the undepreciated net book value of the Reid Garner units and all costs related to the new replacement facilities. (Ex. 65 at 36-39).

215. BCP, however, adds that the law requiring the retirement of Reid Gardner did not specifically address offsetting the mandatory cost deferrals by quantifiable cost reductions/savings. Nevada Power will continue to recover O&M costs included in Docket No. 14-05004 for operating the Reid Gardner Units 1-4 during the entire three-year period (2015-2017), even though the Reid Gardner units have been retired and are no longer operating. (Ex. 65 at 38-40). BCP states that fairness to both shareholders and customers dictates that the O&M revenue Nevada Power is receiving from the now-

shuttered Reid Gardner be treated as a savings that is offset against the costs deferred in regulatory assets mandated by NRS 704.7317. (Ex. 65 at 40-41).

216. BCP adds further that Nevada Power has not tracked any O&M expense savings related to the retirement of the Reid Gardner generating units. (Ex. 65 at 43-44). It has been able to determine Reid Gardner non-fuel O&M savings for 2105 through 2017 by comparing the 2013 O&M expense used as the test year in Docket No. 14-05004 to the Reid Gardner O&M expense levels incurred during the 2015 through 2017 rate-effective period. (Ex. 65 at 45-47).

217. BCP recommends that the calculation of the O&M savings and carrying charge for the O&M savings resulting from the retirement of the Reid Gardner generating units be realized through December 31, 2017. This is consistent with Nevada Power's quantification of the net book value for the Reid Gardner units included in a regulatory asset and the calculation of the regulatory liability proposed to reflect the impact fees collected from NRS Chapter 704B customers. (Ex. 65 at 55-56).

218. Staff recommends that the regulatory asset established by Nevada Power for the retirement and decommissioning of Reid Gardner Units 1-4 be offset by $23.9 million, representing $21.7 million of non-labor O&M expense recovered in rates after the retirement of the Reid Gardner Units 1-4, with a carrying charge of $2.3 million. The $23.9-million dollar reduction to deferred costs in the regulatory asset would be amortized over six years, consistent with the period proposed by Nevada Power. (Ex. 134 at 15-16).

219. Staff states that the PUCN's decision in Docket No. 14-05003 recognized the likelihood for double recovery of O&M costs as a result of the retirement of the Reid Gardner units and directed Nevada Power to track any cost savings so that they could be addressed in this current proceeding. However, Nevada Power has not attempted to quantify any cost savings resulting from the retirement of the Reid Gardner generating units. (Ex. 134 at 12-13).

220. Staff states that although its recommendation in Docket No. 14-05003 was specific to Reid Gardner O&M labor costs, the concern regarding over-recovery also applies to all Reid Gardner non-labor O&M costs once the generating units were retired. The Reid Gardner non-labor O&M expenses were included in rates established in Docket No. 14-05004 and were based upon the assumption that the Reid Gardner units would be operating normally for the full three-year rate-effective period. Nevada Power continued to receive revenue to cover the annual O&M expense assumed in the rates established in Docket No. 14-05004 after the Reid Gardner units were taken out of service during the rate-effective period, 2015-2017. (Ex. 134 at 13-16).

Rebuttal

221. No rebuttal was provided.

PUCN Discussion and Findings

222. The PUCN agrees with the arguments of Staff and BCP to account for the reduction in O&M costs (savings) realized during the prior rate-effective period (2015 through 2017) that resulted from the retirement of Reid Gardner. It is both fair and reasonable. Therefore, the PUCN orders that the regulatory asset established for the new book value of Reid Gardner Units 1-4 be offset by $23.9 million. This offset shall represent $21.7 million of non-labor O&M expenses recovered in rates after the retirement of Reid Gardner Units 1-4, with a carrying charge of $2.3 million. The $23.9-million reduction to deferred costs in the regulatory asset will be amortized over 6 years and is consistent with the period proposed by Nevada Power. It is noteworthy that Nevada Power does not rebut this issue. Indeed, Nevadans should receive the benefit of any cost-saving resulting from the coal-fired generation replacement program because they are being required to pay 100 percent of the costs.

d. Removing Unused Inventory from Unit 4 Regulatory Asset

Party Positions

223. Nevada Power requests recovery of approximately $9.714 million in unused inventory located at Reid Gardner Unit 4. (Ex. 5 at 239, I-CERT-30).

224. Staff recommends disallowing $463,533 of unused inventory at Reid Gardner Unit 4. Staff contends that the unused inventory includes items such as submersible pumps, bolts, electric heaters and air conditioners, valves, switches, and various other equipment that Nevada Power ordered up to December 2016. Staff has concerns with this unused inventory. During 2016, the last year of Reid Gardner Unit 4's operation, Nevada Power spent approximately $463,533 on new inventory. Staff argues that Nevada Power has not met its burden of demonstrating that the decision to purchase that inventory during 2016 was prudent or that any of the items in the unused inventory cannot be reused at other facilities. (Ex. 138 at 22-23).

225. Staff contends that Nevada Power bases its inventory levels at its generating station on a combination of past usage, forecast usage, and equipment failure rates. Staff states that it does not believe that it is reasonable for Nevada Power to automatically reorder equipment during the last year of operation of any generating unit simply because inventory falls below a prescribed level. Instead of discarding the unused inventory, Nevada Power should evaluate whether it can be used at other generating facilities. (Ex. 138 at 23-24).

Rebuttal

226. Nevada Power disagrees with Staff's proposal. The 2016 procurement of inventory for Reid Gardner was prudent. The inventory procured was restricted to plant materials that plant operators specifically identified as being necessary for Reid Gardner Unit 4. Nevada Power did not procure the

inventory based on restocking or any general inventory minimum. Moreover, Nevada Power did pursue using some of the unused inventory at other generating stations. In addition to internal reuse of inventory, Nevada Power also enlisted third-party asset recovery vendors to market plant equipment. Third-party interest in equipment and materials was limited. Nevada Power contends that it exercised care and prudence in making a limited purchase of 2016 inventory needed to maintain plant reliability during the expected remaining operation of Reid Gardner Unit 4. (Ex. 153 at 9-11).

PUCN Discussion and Findings

227. The PUCN finds that the procurement by Nevada Power of inventory for Reid Gardner Unit 4 was reasonable. The PUCN declines Staff's proposed disallowance. The inventory purchase was specific and necessary in 2016 for the continued reliable operation of Unit 4. Moreover, the records shows that Nevada Power did make mitigation efforts by using some of the inventory at other generation facilities and enlisting thirty-party vendors to market plant equipment.

e. Environmental Cleanup Costs for Units 1-3 Prior to Docket No. 14-05003

Party Positions

228. Nevada Power entered into an Administrative Order on Consent (AOC) with NDEP in 2008 to address soil and groundwater contamination associated with operation of Reid Gardner. (Ex. 83 at 7).

229. Later, in 2013, the Nevada State Legislature passed Senate Bill 123. That bill required Nevada Power to retire coal power plants early, including Reid Gardner, and also required Nevada Power to develop an ERCR plan, which, in part, included the costs of decommissioning, demolition, and remediation. The PUCN approved the ERCR plan in Docket No. 14-05003 in 2014. In that Order (and as previously discussed) the PUCN established separate regulatory asset accounts for the accumulation of decommissioning and remediation costs for the Reid Gardner Units 1-3 and Reid Gardner Unit 4. The PUCN ordered the retirement of Reid Gardner Units 1-3 by December 2014 and Reid Gardner Unit 4 by December 31, 2017. (Ex. 83 at 6-7). Later, in 2016 in Docket No. 16-08026, the PUCN revised the retirement date for Reid Gardner Unit 4 to the date on which all remaining coal reserve had been used. Reid Gardner Unit 4 was retired on March 11, 2017. (Ex. 83 at 7).

230. Nevada Power contends that it is entitled to all environmental cleanup costs associated with Units 1-3 pursuant to the AOC issued by NDEP that occurred prior to the PUCN's approval of the two regulatory assets for the Reid Gardner units in Docket No. 14-05003 and that were included in the Plant-in-Service accounts for Reid Gardner Units 1-3. The net amount booked to Plant-in-Service for 2014 and prior was $5.151 million. (Ex. 83 at 19-21).

231. Staff recommends that $5.196 million in site remediation costs charged to Reid Gardner Units 1-3 prior to the PUCN's decision in Docket No. 14-05003 be transferred from the Reid Gardner Units

1-3 Plant-in-Service accounts to the Reid Gardner Units 1-4 regulatory asset account. This treatment will result in all decommissioning and remediation costs being tracked in one regulatory asset account that can be used for future reference in the event of additional generating unit retirements, such as the decommissioning of North Valmy and Navajo coal plants. This treatment would also be consistent with Staff's recommendation that rate recovery for all Reid Gardner remediation and decommissioning costs not occur sooner than Nevada Power's next General Race Case in 2020. Staff states that Nevada Power should be allowed to book a carrying charge to the regulatory asset until rate recovery is approved in a future case. (Ex. 138 at 21-22).

Rebuttal

232. Nevada Power opposes Staff's proposed treatment of the Reid Gardner AOC costs. Nevada Power argues that it incurred these costs while performing work on projects that were completed before the PUCN established the ERCR plan process. Adoption of Staff's recommendation would further delay commencement of the recovery of the AOC costs incurred between 2011 and 2014 until no sooner than 2020. (Ex. 153 at 13). Nevada Power maintains that it will continue to carefully track remediation costs to address Staff's concern about the clarity of the overall Reid Gardner decommissioning, demolition, and remediation costs. (Ex. 153 at 13).

PUCN Discussion and Findings

233. The PUCN disagrees with Staff and finds that recovery of the AOC environmental cleanup ordered by NDEP and incurred by Nevada Power between 2011 and 2014 is fair. It is relevant that closure of Reid Gardner was mandated by legislation and public policy considerations—it was forced. Approving Nevada Power's request on this issue balances the PUCN's decision to defer other costs until 2020. Moreover, the PUCN finds that little-to-no historical basis exists for Staff's recommended transfer of $5.196 million from the Reid Gardner Units 1-3 Plant-in-Service account to the regulatory assets account. Nevada Power's accounting for the $5.196 million spent on remediation was proper.

f. Deferral of Units 1-4 Property Tax and Insurance in a Regulatory Asset

Party Positions

234. Nevada Power seeks inclusion of its test period property tax and insurance expenses, including property tax and insurance expenses associated with Reid Gardner Units 1-4 in its cost of service for the purpose of revenue requirement calculation. (Ex. 3 at 134, 167; Ex. 4 at 158; Ex. 70 at 105, 164, 356; Ex. 76 at 2-3).

235. Staff recommends that $1.335 million in property taxes and $127,000 in insurance expense related to Reid Gardner Units 1-4 be recorded as decommissioning regulatory assets set up for the Reid Gardner Units 1-4 instead of as on-going operating costs beginning January 1, 2018, and going

forward. (Ex. 139 at 4-9). If these expenses are allowed to remain in the cost of service as normal operating expenses and are allocated to all customer classes, the NRS Chapter 704B customers will avoid responsibility for 60 percent of these costs. This will occur because property taxes and insurance costs related to Reid Gardner Units 1-4 are allocated among three categories: generation, transmission, and distribution. Approximately 45 percent is allocated to the generation bucket, 15 percent to the transmission bucket, and 40 percent to the distribution bucket. As DOS customers, NRS Chapter 704B customers do not pay any Reid Gardner property taxes or insurance costs that end up in the generation and transmission buckets. (Ex. 139 at 4-9).

236. Conversely, Staff maintains that, if the property tax and insurance costs are recorded as regulatory asset items, NRS Chapter 704B customers will be responsible for their load ratio share of these costs, which is consistent with NRS 704B.310(6)'s mandate that neither the utility nor remaining customers be burdened with increased costs as a result of an NRS Chapter 704B customer's departure. Holding NRS Chapter 704B customers responsible for their proportionate share of these costs is also consistent with the PUCN's obligation to order terms, conditions, and payments that are fair and nondiscriminatory as between the departing customer and the remaining customers pursuant to NRS 704B.310(7). (Ex. 139 at 5-6, 8-9).

Rebuttal

237. Nevada Power asserts that Staff's calculations for the test year property and excess liability insurance expense related to Reid Gardner Units 1-4 contains errors that must be corrected if its recommended adjustments of $127,000 are accepted. Nevada Power proposes the following:

> •Recalculate the test period amount of $567,998 in property insurance premiums, which is attributable to all Nevada Power generation, to exclude $74,519 in property insurance premiums related to Silverhawk and include property insurance premium costs associated with Reid Gardner Units 1-3;
>
> •Change the test period cost of excess liability insurance premiums attributable solely to Reid Gardner Units 1-4 to $387,327, instead of the $1,205,743 amount used by Staff;
>
> •Reduce the calculated percentage of property insurance premium allocable to Reid Gardner Unit 4 from 7.14 to 5.3 percent to properly account for the Reid Gardner units 1-4 share of the charges captured in the property insurance account 924; and
>
> •For the purposes of property insurance costs calculations, replace Reid Gardner unit 4 net book value ($140,636,000) with Reid Gardner Unit 4 Total Insurable Value ($135,970,455).

238. The first three corrections reduce Staff's proposed adjustment from $127,000 to $30,003. The final correction further reduces the adjustment to $29,707. (Ex. 142 at 30-33). With regard to property taxes, Nevada Power recommends using the estimated property tax for 2018, $418,000, in lieu of the test-year amount used by Staff.

PUCN Discussion and Findings

239. The PUCN finds that the property tax and insurance expenses attributable to Reid Gardner Units 1-4 should be recorded as decommissioning regulatory assets, instead of as ongoing operating costs beginning January 1, 2018, and going forward. This treatment will ensure that NRS Chapter 704B customers pay their proper share of those costs based on NRS 704B.310(6) and (7) mandates. No NRS Chapter 704B customers have objected to this proposal. Staff's adjustments for property and liability insurance is adopted, subject to the above-listed corrections identified by Nevada Power. Staff's adjustment for property tax is adopted as proposed. The PUCN rejects Nevada Power's proposed use of a 2018 property tax, as it is well beyond the May 31, 2017, certification date established for this case.

g. Operating and Maintenance (O&M) and Benefit Savings from the Retirement of Unit 4

Party Positions

240. Nevada Power retired Reid Gardner Unit 4 on March 11, 2017, pursuant to the second amendment to the ERCR plan approved in Docket No. 16-08026. (Ex. 83 at 6-7).

241. Staff recommends that the test year O&M expense be reduced by $1,397,000 to reflect the expected reduction in overtime payroll, benefits, and payroll tax expenses resulting from the closure of Reid Gardner Unit 4. Reid Gardner Unit 4 was closed in March 2017. As a result, Nevada Power transferred 12 Reid Gardner employees to the Arrow Canyon Complex to improve coverage and reduce overtime. Nevada Power expects a reduction in overtime payroll, benefits, and payroll tax expenses in 2019 following training of the 12 transferred employees. If the expected savings from the closure of Reid Gardner Unit 4 are not reflected in this case, all savings that occur in 2019 and 2020 will accrue to the benefit of Nevada Power's shareholders. (Ex. 139 at 10-11; Tr. at 1293-98).

Rebuttal

242. Nevada Power recommends rejection of Staff's proposal that assumes a future payroll expense deduction of $1.397 million. The ratemaking process in Nevada relies on 'known and measurable' adjustments to a historical test year. Projected overtime savings at the Arrow Canyon Complex is nothing more than a guess at this time and should not be used for setting revenue requirement in this case. (Ex. 154 at 38).

PUCN Discussion and Findings

243. The PUCN rejects the $1.397 million payroll adjustment proposed by Staff. NAC 703.2461 provides for certified adjustments up to six months beyond the chosen historical test year. The original certification date for this case was May 31, 2017. All adjustments must be known, measureable, and in effect by the end of the certification period. Staff's adjustment reaches well beyond the certification period to capture estimated savings in 2019 and 2020 resulting from the closing of Reid Gardner Unit 4 and the resulting transfer of 12 Reid Gardner Unit 4 employees to the Arrow Canyon Complex. General rate cases and certification periods must have beginnings and ends.

h. Flood Control Project Reclassification

Party Positions

244. Nevada Power states that it has accurately accounted for Reid Gardner net book value and decommissioning costs. In Docket No. 14-05003, the PUCN approved regulatory asset treatment for the costs associated with the retirement of Reid Gardner. These approved costs included the net book value of Reid Gardner's four units and related electric investments as of December 31, 2017. (Ex. 83 at 11-12).

245. Staff recommends adjusting some of these Reid Gardner costs. Staff recommends reclassifying the Reid Gardner RC1015 Storm Water/Flood Control Project (Reid Gardner storm water project) from net book value of Reid Gardner Unit 4 to the appropriate transmission plant asset account, which is Account No. 352-Structures and Improvements. The Reid Gardner storm water project had a final cost of nearly $528,000 and was presumably put into service at the end of December 2015. (Ex. 83 at 11-12; Ex. 134 at 5-6).

246. Staff further recommends reclassifying the Reid Gardner storm water project because the storm water project's primary purpose and benefit was to protect the Reid Gardner transmission switchyard from flash flooding. Reid Gardner Units 1-3 and Unit 4 were required to be retired at the end of 2014 and 2017, respectively. While the generating station is due to be demolished, the transmission facilities will remain, and the storm water project will provide benefits to these facilities. Nevada Power should have booked the storm water project costs to the transmission and switchyard plant account and not to the coal generation plant. Staff's recommendation does not change the ability of Nevada Power to recover these costs; it simply changes the accounting structure through which the costs are recoverable. (Ex. 138 at 2, 14-15).

Rebuttal

247. Nevada Power agrees with Staff's recommendation to reclassify the storm water project costs from the Reid Gardner net book value to the Reid Gardner transmission switchyard net book value.

The investment in the storm water control measures protects the remaining transmission facilities that will continue to be used and useful, beyond the decommissioning of the power plant. While Nevada Power agrees with Staff's recommendation to change the accounts, Nevada Power does not agree with Staff's calculations of the net book value balance at May 31, 2017, in the regulatory asset account. Nevada Power maintains that Staff applied the incorrect depreciation rate for the generation asset retirement. Staff did not use the transmission allocator for its reclassification adjustments to plants in service, accumulated provision for depreciation, or annualized depreciation expense. (Ex. 145 at 5).

PUCN Discussion and Findings

248. The PUCN approves the reclassification of the storm water project costs from the Reid Gardner net book value to the Reid Gardner transmission switchyard net book value. Both Nevada Power and Staff are in agreement on this matter.

249. The PUCN also approves Nevada Power's accounting calculations presented in rebuttal for the correct account amounts. While the Reid Gardner generating station is due to be demolished, the transmission facilities will remain, and the storm water project will provide benefits to the transmission facilities. Nevada Power should have booked the storm water project costs to the transmission and switchyard plant account, not to the coal generation plant. Staff's recommendation does not change the ability of Nevada Power to recover these costs—it simply changes the accounting through which the costs are recoverable.

i. Fuel Stock

Party Positions

250. Nevada Power did not make an adjustment to remove the fuel stock from the Reid Gardner plant from rate base reflected in Statement N. (Ex. 4 at Statement N).

251. SEA states that Nevada Power did not make an adjustment to remove the fuel stock from the Reid Gardner plant from rate base when Nevada Power removed costs associated with the Reid Gardner plant from rates. The fuel stock amounts are approximately $8,295,068, which flow to Nevada Power's results of operations, without a corresponding adjustment to remove these amounts. Removing the fuel stock results in an approximate $1,013,535 reduction to revenue requirement. (Ex. 49 at 36-36).

Rebuttal

252. Nevada Power state that SEA correctly identified an adjustment Nevada Power should have made to its Statement N. However, Nevada Power notes that SEA incorrectly used the December 2016 balance in the "other rate base additions" work papers to remove the fuel stock. Nevada Power, instead,

used a 13-month average balance for Reid Gardner RG-1-4 fuel stock in Statement N—Other Rate Base Additions.

PUCN Discussion and Findings

253. SEA and Nevada Power are in agreement. The PUCN accepts SEA's proposed adjustment, with the accounting corrected by Nevada Power's rebuttal testimony. Given its closure in early 2017, the Reid Gardner fuel stock should not be reflected in rate base going forward.

j. Contamination of Evaporation Ponds

Party Positions

254. Nevada Power seeks recovery of costs for decommissioning, demolishing, and remediating the Reid Gardner site, including remediation costs for evaporation ponds, prior to December 31, 2017, as well as costs incurred through the end of the certification period. (Ex. 83 at 3).

254A. BCP contends that the $13.374 million in costs that Nevada Power incurred to remove and replace evaporation ponds should be disallowed. Ratepayers should not be held accountable for permit violations at Reid Gardener or for improper cleanup efforts. The purpose of the Reid Gardner evaporation ponds was to receive discharged wastewater from the plant and to then hold the wastewater until evaporation could remove the liquid waste. (Ex. 123 at 2, 6-9).

255. In the late 1990s to the mid-2000s, Nevada Power replaced the clay-lined evaporation ponds with double lining. Nevada Power was required to remove all of the contaminated soil below the ponds. Any contamination during the current remediation process must have occurred after Nevada Power replaced the old clay lining with the new double lining, if Nevada Power properly remediated any contamination during the lining replacement process. Nevada Power had a responsibility when it first replaced the lining, and has a responsibility now, to clean up any contaminated groundwater under the evaporation ponds. (Ex. 123 at 2, 6-9; Tr. at 1080-1088).

Rebuttal

256. Nevada Power disagrees with BCP. Nevada Power states that the costs that it included in this case were expended through 2016 to remove and dispose of pond solids, not to remove and replace the evaporation ponds. BCP has not identified any costs associated with the replacement of evaporation ponds or pond area remediation activities. (Ex. 153 at 13-14). Nevada Power states that the State of Nevada actually approved the design of the original ponds, and they were built to the standards and practices accepted by the State environmental agencies at the time. Nevada Power has complied with all NDEP findings and permits that relate to the ponds, and NDEP has never issued to Nevada Power any violations associated with any discharge permits. (Ex. 153 at 14-18).

257. Nevada Power adds that it is required to remove the evaporation pond solids as part of Reid Gardner's decommissioning and dismantling by the Bureau of Water Pollution Control. Additionally, the PUCN has previously approved recovery of the same actions in other ponds in Docket Nos. 14-05004 and 11-06006. Nevada Power contends that the $13.374 million in costs associated with removal and disposal of pond solids was prudently incurred and necessary to complete the pond closure requirements of the NDEP Bureau of Water Pollution Control. (Ex. 153 at 18-19).

PUCN Discussion and Findings

258. The PUCN finds that whether or not the $13.374 million associated with removing and disposing of pond solids was prudently incurred and necessary to complete the pond closure requirements of the NDEP's Bureau of Water Pollution Control will be deferred, along with other Reid Gardner environmental cleanup costs, until the next general rate case in 2020.

k. Groundwater Contamination and Remediation

Party Positions

259. Nevada Power seeks recovery for costs related to Reid Gardner Units 1-4 retirement. Nevada Power states that the costs it incurred for decommissioning, demolishing, and remediating the Reid Gardner site are reasonable, including costs incurred for potential groundwater contamination remediation. As part of the remediation efforts, nine potential petroleum source areas were identified within an area that was a former underground piping and petroleum tank. (Ex. 83 at 3, 27).

260. BCP recommends disallowing recovery of $2.479 million in costs that Nevada Power incurred to address groundwater contamination at Reid Gardner. BCP states that the history of the petroleum groundwater contamination at Reid Gardner is why it is recommending the disallowance. Ratepayers should not be held accountable for the costs of the groundwater contamination work because Nevada Power did not take proper measures to contain the petroleum leaks in the Reid Gardner system. (Ex.123 at 2, 10; Tr. at 1082). BCP states that it is normal maintenance practice to address a leak immediately. If Nevada Power had properly managed the Reid Gardner system, then there would have been no groundwater contamination. (Tr. 1087).

261. BCP explains that diesel fuel was discovered floating on groundwater in the late 1980s at the petroleum source area of the Reid Gardner site, likely from former underground diesel-fuel piping. A diesel recovery system, which recovers contaminated groundwater, began operation in 1998, was upgraded in 2003, and was upgraded again in 2013. An investigation, which began in 2015, is currently underway to delineate the extent of petroleum impacts to soil and groundwater. (Ex.123 at 9).

Rebuttal

262. Nevada Power disagrees with BCP and states that all petroleum source area remediation costs, including the source area identified by BCP, are being prudently incurred under the supervision of NDEP and should be included in rates. (Ex.153 at 23; Tr. at 1475-1477). Nevada Power maintains that BCP's summary of the history of the petroleum remediation activities and costs at Reid Gardner are incorrect because BCP only considered one petroleum source area, which concerned former underground piping.

263. Nevada Power explains that free product (diesel) was discovered at the particular source area identified by BCP during a 1985 geotechnical investigation. The costs included in this rate case for that particular area are $1.05 million. The remaining costs included in BCP's calculated disallowance are related to other potential petroleum source areas. Nevada Power has received "no further action" determinations for four petroleum sites. BCP provides no evidence that Nevada Power's operating, inspection, and maintenance practices prior to the 1985 identification of one petroleum source were unreasonable or deficient based on the practices of the time. (Ex. 153 at 20).

264. Nevada Power further disagrees with BCP's position that it did not take proper measures to contain leaks. BCP did not demonstrate that Nevada Power's practices were deficient or unreasonable. All petroleum-source area remediation costs are being prudently incurred under the supervision of NDEP and should be included in the cost of service in this rate case. (Ex. 153 at 23).

PUCN Discussion and Findings

265. The existence of any gasoline in groundwater is a problem that rarely, if ever, occurs without some type of negligence or fault. It is unacceptable—always.

266. The PUCN questions the propriety of requiring ratepayers to cover the $2.497 million in costs related to groundwater contamination remediation at the Reid Gardner at this time. Nevertheless, the PUCN finds that Nevada ratepayers should not be held accountable for the costs of the remediation work thus far because Nevada Power has provided insufficient evidence to justify the prudency of its actions and fundamental question of why ratepayers should be held financially responsible for the cleanup and how the pollution occurred remain unanswered.

267. The PUCN directs Nevada Power to present detailed evidence at the next general rate case in 2020 regarding how and why any groundwater contamination occurred, what steps are being taken to remediate any contamination, and what costs are being incurred to do so in its next general rate case. The PUCN is encouraged that NDEP is involved in the remediation process; but, the PUCN does not believe it has all of the relevant information necessary at this time to extent of the groundwater contamination and any potential remediation efforts in this case.

2. Navajo Generating Station

a. Operation and Maintenance (O&M) Expenses

Party Positions

268. Nevada Power has included test period O&M expenses related to its interest in the Navajo generating station. (*See* Ex. 70 at Statement I).

269. SEA states that a deferral should be created to capture the revenue requirement effects of retiring Navajo. The deferral would have the effect of eliminating the depreciation expenses, other operating costs, and rate base items reflected in rates, with the exception of any ongoing regulatory amortizations. Because Navajo is scheduled to close by the end of 2019, Nevada Power will no longer incur a number of ongoing costs associated with the plant. (Ex. 49 at 20-21).

270. BCP asserts that Nevada Power should be ordered to defer within a regulatory liability account, with carry, all non-fuel O&M expense savings that are realized once Navajo is retired at the end of 2019. Nevada Power has included test year O&M expenses incurred at Navajo within the development of its proposed retail cost of service. Upon the plant's 2019 retirement, Nevada Power will no longer incur O&M expenses there. (Ex. 65 at 56).

Rebuttal

270A. No rebuttal was provided.

PUCN Discussion and Findings

271. The PUCN finds it appropriate to incorporate into a regulatory liability the O&M expenses Nevada Power will not incur in 2020 as a result of Navajo's early retirement. As such, the PUCN accepts BCP's recommendation to defer all non-fuel O&M expense savings from Navajo's retirement into a regulatory liability. Non-fuel O&M expenses for Navajo are included in the test period cost of service, as acknowledged by both SEA and BCP. As with depreciation expense, Nevada Power will no longer experience some, if not all, O&M costs after Navajo's retirement in 2019.

272. The PUCN directs Nevada Power to record the non-fuel O&M costs in the same regulatory liability account as the Navajo plant depreciation expense and to include carrying charges.

b. Regulatory Asset Cost Recovery

Party Positions

273. MGM states that the PUCN should determine in this case MGM's liability for any remaining Navajo net book value costs and decommissioning costs. MGM expresses concerns with how Nevada Power has credited and allocated impact fees paid by MGM—a distribution-only service customer—for the next three years. Particularly, because the impact fee already paid by MGM included BTGR revenues at current rates through and beyond the next rate period, if Nevada Power does not require a

revenue requirement increase, then the impact fees already paid by MGM are more than adequate to recover Reid Gardner and Navajo costs during the same period. To charge any additional fees to MGM for Reid Gardner and Navajo costs in addition to the amount of impact fees already paid by MGM would be punitive. (Ex. 118 at 10).

Rebuttal

274. No rebuttal is provided.

PUCN Discussion and Findings

275. Nevada Power is not seeking recovery of any retirement, decommissioning, or remediation costs related to the Navajo plant in this case. Accordingly, the PUCN finds that MGM's position regarding its impact fee and recovery of Navajo costs is not ripe for consideration at this time.

c. Regulatory Asset Carrying Charge

Party Positions

276. Nevada Power is scheduled to retire the Navajo generating plant at the end of 2019. (Ex. 47 at 3; Ex. 48 at 12, 21).

277. SEA states that any regulatory asset established as a result of early retirement of Navajo should not earn any carrying charge or, at most, should earn a carrying charge to compensate for the time value of money. After 2019, Navajo will no longer be used and useful for providing electric services to Nevada Power customers. Moreover, there are no statutory provisions that require a carrying charge on net plant balances. Lastly, shareholders have been compensated for the risk of early retirement through the return they earn on the plant while it is in service. (Ex. 49 at 57).

Rebuttal

278. Nevada Power contends that SEA's position is contrary to the ERCR regulations and statutes, is contrary to the ERCR plan that has been previously adopted and approved. (Ex. 142 at 24).

PUCN Discussion and Findings

279. The PUCN approved Nevada Power's ERCR plan in Docket No. 14-05003, as well as the accumulation of carrying charges on a decommissioning and remediation regulatory asset. It is mandated. Accordingly, the PUCN finds that the net book value and future decommissioning and remediation costs related to Navajo should be accounted for in the same manner as Reid Gardner Units 1-4 on their retirement. That is, the net book value is recorded in a regulatory asset without carry charges, and incremental costs relating to the decommissioning and remediation of the Navajo site are recorded in a regulatory asset that accrues carrying charges.

280. Additionally, the PUCN finds that any prospective determinations with respect to the prudence or clerical accuracy of the Navajo generating plant net book value on retirement, and decommissioning

and remediation costs, are not ripe for consideration at this time. These will be reviewed in the next general rate case in which Nevada Power requests recovery of the Navajo net book value and decommissioning and remediation costs in rates.

3. Las Vegas Cogeneration

a. Normalizing Operating and Maintenance (O&M) Expenses

Party Positions

281. Nevada Power requests approximately $5.147 million in O&M expenses for LV Cogen. The test period 2016 O&M costs for LV Cogen were adjusted (normalized) by removing planned outages and other large non-recurring costs to determine a recommended level of O&M costs, based upon best utility practices. LV Cogen houses three natural-gas-fueled generating units and is located in North Las Vegas. The purchase price for LV Cogen was $130.82 million, and it was included in Docket No. 14-05003. Nevada Power notes that the PUCN approved the acquisition of LV Cogen in Docket No. 14-05003 as a part of the generation capacity to replace retired coal-fired generating capacity. (Ex. 81 at 1, 17, 21; Ex. 154 at 40-41).

282. Staff recommends reducing Nevada Power's requested O&M amount for LV Cogen by $1.661 million to reflect normal operations. Staff states that the average annual level of O&M expense incurred for LV Cogen since its acquisition has been $17.2 million. Staff states that this amount is threefold what Nevada Power represented to the PUCN in Docket No. 14-05003. The amount of O&M expense in the LV Cogen regulatory asset account as of May 31, 2017, was $41.58 million, with an additional $3.5 million in carrying charges. Nevada Power projected in Docket No. 14-05003 that $6.2 million of annual O&M expense, which equates to $14.98 million over a two-year-and-five-month period, would be recorded in a regulatory asset, accrue a carrying charge, and be placed into rate base. Therefore, there is $26.6 million more O&M expense in the LV Cogen regulatory asset (not including carry), than what Nevada Power originally represented. (Ex. 136 at 3-5; Tr. at 1223-26.)

283. Staff states that it does not believe Nevada Power's decisions regarding the O&M expenses Nevada Power incurred over the past two years and five months at LV Cogen were imprudent. Staff states that it does not take issue with Nevada Power's decision to accelerate the overhaul schedule, nor does it recommend a disallowance of the costs Nevada Power accumulated in the regulatory asset account. Rather, Staff is concerned that Nevada Power is requesting to recover O&M costs in the LV Cogen regulatory asset that are triple the amount Nevada Power said they would be in Docket No. 14-05003. (Ex. 136 at 6).

284. Staff recommends removal of $1.661 million of Nevada Power's proposed normalized annual O&M expense. Reducing the O&M expense by approximately $1.7 million will leave an ongoing

annual O&M expense of approximately $6.2 million, which is the amount that Nevada Power calculated and represented to the PUCN in Docket No. 14-05003. (Ex. 136 at 7-8).

Rebuttal

285. Nevada Power argues that the cost estimates that it provided to the PUCN in Docket No. 14-05003 were not a realistic indication of the O&M requirements for running LV Cogen. The estimates provided in Docket No. 14-05003 were based on the cost data provided by the previous owners of LV Cogen, who operated as independent power producers. At that time, LV Cogen was operating for an extended period of time with limited production. This is a very different operating scenario than what the Station is currently experiencing. (Ex. 154 at 40).

286. Nevada Power states that it has provided an accurate expectation of costs for LV Cogen. The actual experienced 2016 non-labor O&M expenses were $13.781 million. Starting with the expenditure, Nevada Power went through a process of removing expenditures that were one-time expenses or that experienced higher-than-normal costs due to the acquisition or outage accelerations. The types of costs removed from the actual expenditures were planned and specific forced outages and higher-than-normal maintenance work on plant equipment. (Ex. 154 at 40-41).

287. Nevada Power states further that Staff did not have issues with specific costs and did not point out any costs included in the normalized test year adjustments that were improper, excessive, or one-time in nature. The only issue raised by Staff was that the costs were higher than those represented in Docket No. 14-05003. However, upon taking ownership of LV Cogen, Nevada Power began filing updated unit cost assumptions. (Ex. 154 at 42).

PUCN Discussion and Findings

288. The PUCN finds that Nevada Power's requested O&M expenditures for LV Cogen are reasonable and rejects Staff's proposed disallowance. Nevada Power removed planned outages and other large non-recurring costs to determine the appropriate level of O&M costs. Staff did not take issue with specific costs and did not point out any costs included in the normalized test year adjustments that were improper, excessive, or one-time in nature.

b. Major Overhaul Costs

Party Positions

289. Nevada Power seeks to recover $6,363,708 in costs related to a major overhaul of LV Cogen. In doing its due diligence when it purchased LV Cogen, Nevada Power learned that some of the turbines had 44,224 hours of operation. The turbines' manufacturer recommends a major inspection and repair every 43,000 to 45,000 hours of service for a cycling turbine. Based on historical operating hours, Nevada Power developed a plan to do a major inspection of the turbines starting in 2017.

However, due to the actual run-hours of the turbines, and due to mechanical issues, it became necessary for Nevada Power to accelerate the turbines' overhaul schedule. (Ex. 81 at 57-58; Ex. 82 at 12).

290. SEA states that the costs for the LV Cogen overhaul were not prudently incurred, and that Nevada Power did not disclose the need for the turbines' overhaul to the PUCN at the time Nevada Power purchased LV Cogen. Nevada Power's due diligence was insufficient to discover the major issues related to the turbines and the need for the overhaul. (Ex. 49 at 36-37).

Rebuttal

291. Nevada Power disagrees with SEA and states that the need for the turbine overhauls was noted at the time Nevada Power purchased LV Cogen in 2014. Nevada Power argues that it initially planned to complete one turbine overhaul in each of three successive annual outages. This plan was identified during the due diligence phase of purchasing the plant and was presented in Docket No. 14-05003, where approval was granted for the acquisition of LV Cogen. Due to the value of the LV Cogen units to Nevada Power customers, Nevada Power successfully operated the units more than originally anticipated in 2014. The benefits to ratepayers of LV Cogen's greater operation have been reflected in the annual DEAA process. As a consequence of greater usage, the turbines reached their operating hours sooner than expected in 2014. (Ex. 154 at 28-30).

PUCN Discussion and Findings

292. The PUCN finds that the costs for the LV Cogen overhaul costs of $6,363,708 are reasonable and, therefore, they are approved. The need for the turbine overhauls was noted at the time Nevada Power purchased LV Cogen in 2014 and was presented to the PUCN in Docket No. 14-05003. Due to greater usage, the turbines reached their high level of operating hours sooner than expected in 2014.

4. Sun Peak Generating Station

a. Normalizing Operating and Maintenance (O&M) Expenses for Sun Peak

Party Positions

293. Nevada Power requests $725,000 in O&M expenses for the Sun Peak Generating Station. The Test Period 2016 O&M costs for Sun Peak were adjusted (normalized) by removing planned outages and other large non-recurring costs to determine a recommended level of O&M costs, based upon best utility practices. Sun Peak houses three natural-gas-fueled generating units and is located in Las Vegas. The purchase price for Sun Peak was $15.83 million, and it was included in Docket No. 14-05003. The PUCN approved the acquisition of Sun Peak in Docket No. 14-05003 as a part of the generation capacity to replace retired coal-fired generating capacity. (Ex. 81 at 1, 17, 21-22)

294. Staff recommends removing $1.172 million of Nevada Power's proposed normalized annual O&M expense for Sun Peak from Nevada Power's revenue requirement. Nevada Power wanted to

acquire the Sun Peak as replacement capacity for coal plant retirements, and provided information to in Docket No. 14-05003 that the average annual O&M costs for the Station would be approximately $0.6 million. The actual average O&M expense since the purchase of Sun Peak (including the certification period ending May 31, 2017), has averaged, on an annualized basis, approximately $2.1 million. This amount is over three times what Nevada Power represented in Docket No. 14-05003. (Ex. 136 at 9).

295. Staff states further that Nevada Power is proposing to include in its revenue requirement an annual O&M expense for Sun Peak that is too high and not reflective of going-forward costs. Nevada Power has provided limited justification or explanation of the rate base and revenue requirement impacts that resulted from these costs in this case. Because Nevada Power has offered no explanation for why the O&M expenses to date exceeded what Nevada Power presented in Docket No. 14-05003, Staff states that it does not believe Nevada Power has justified any increase in the ongoing annual O&M expense at Sun Peak. (Ex. 136 at 10; Tr. at 1223-26).

Rebuttal

296. Nevada Power argues that the cost estimates that it provided in Docket No. 14-05003 were not a realistic indication of the O&M requirements for running Sun Peak. The estimates provided in Docket No. 14-05003 were based on the cost data provided by the previous owners of Sun Peak, who operated as independent power producers. At that time, Sun Peak was operating for an extended period of time with limited production. It was a very different operating scenario than what the Station is currently experiencing. (Ex. 154 at 40).

297. Nevada Power adds that it has provided an accurate expectation of costs for Sun Peak. The actual experienced 2016 non-labor O&M expenses were $1.329 million. Starting with the expenditure, Nevada Power went through a process of removing expenditures that were one-time expenses or that experienced higher-than-normal costs due to the acquisition or outage accelerations. The types of costs removed from the actual expenditures were planned and specific forced outages and higher-than-normal maintenance work on plant equipment. (Ex. 154 at 40-41).

298. Nevada Power adds further that Staff did not have issues with specific costs and did not point out any costs included in the normalized test year adjustments that were improper, excessive, or that were one-time in nature. The only issue that Staff raised was that the costs were higher than those represented in Docket No. 14-05003. However, upon taking ownership of Sun Peak, Nevada Power began filing updated unit cost assumptions with the PUCN. (Ex. 154 at 42).

PUCN Discussion and Findings

299. The PUCN finds that Nevada Power's requested O&M expenditures for Sun Peak are reasonable and approved without Staff's disallowance. Nevada Power removed planned outages and other large non-recurring costs to determine the appropriate level of O&M costs. Staff did not raise issues with specific costs and did not point out any costs included in the normalized test year adjustments that were improper, excessive, or that were one-time in nature. For the foregoing reasons, the PUCN approves Nevada Power's requested O&M expenditures.

b. Controls Retrofit and Related Depreciation Expense

Party Positions

300. Nevada Power seeks recovery of $2,109,100 of costs related to the retrofit of control systems at Sun Peak. Nevada Power purchased Sun Peak in December 2014. During the due diligence process, it was determined that the balance-of-plant and combustion turbine control systems were obsolete and required replacement. Vendors no longer supported these control systems. Nevada Power decided that the most viable option was to replace these systems with new vendor-supported systems. While the PUCN did not previously approve this project, the PUCN found that Nevada Power had performed a reasonable due diligence review of Sun Peak in Docket No. 14-05003. All facilities installed are in-service and used and useful. The controls systems replacement project was prudently designed and constructed, and the costs of the project were prudently incurred. (Ex. 81 at 63-64).

301. BCP recommends that the PUCN disallow recovery of the approximate $2.109 million for the Sun Peak control systems replacement project. BCP explains that the Sun Peak units are peaking units that only operate in summer hours, for short periods. Nevada Power has operated Sun Peak successfully for the last 25 years with the existing controls, and spare parts never became an issue until Nevada Power purchased the plant in 2014. BCP states that, further, there is an adequate after-market for the control system spare parts. Considering the low operating hours of Sun Peak, and that it has less than 10 years of life left, the control systems upgrade was unwarranted. (Ex. 123 at 13-14).

Rebuttal

302. Nevada Power disagrees with BCP's recommendation. One of the reasons why the Sun Peak control system needed to be replaced is that the existing control system was no longer supported by the original equipment manufacturer. Continuing to operate the old control system posed unnecessary risks to assets relied upon during peak periods. (Ex. 154 at 33). Nevada Power states that the Sun Peak control systems project was previously approved by the PUCN in Docket No. 14-05003. (Ex. 154 at 33-34).

PUCN Discussion and Findings

303. The PUCN previously approved the controls systems project in Docket No.14-05003 and, therefore, rejects BCP's recommendation to disallow recovery of $2.109 million for the Sun Peak control systems costs. All facilities installed are in-service and used and useful. The controls systems replacement project was prudently designed and constructed, and the costs of the project were prudently incurred.

C. NON-EMISSIONS REDUCTION AND CAPACITY REPLACEMENT PLAN (ERCR) COSTS

1. Higgins Generating Station

a. Transformer Replacement and Related Depreciation Expense

Party Positions

304. Nevada Power seeks recognition of $4,576,322 related to the replacement of a transformer and associated equipment and structures at the Higgins Station due to catastrophic failure. A transformer suffered a catastrophic failure in October 2015 due to a high voltage bushing failure. The fire from the failure compromised the transformer containment pad and firewall, and it also destroyed a large section of the iso-phase bus feeding low side of the transformer, as well as the isolation switch and parts of the structure supporting the switch on the high side of the transformer. Although the failure was a result of a high-voltage bushing failure, the precise mode of the bushing failure is unknown. Nevada Power states that all of the facilities installed, including the replacement project, are in-service and used and useful. The replacement project was prudently designed and constructed, and the costs of the project were prudently incurred. (Ex. 81 at 75-76).

305. BCP recommends postponing rate basing the approximate $4.623 million that Nevada Power spent for the failed transformer at Higgins until ongoing litigation for the failed transformer is resolved. BCP recommends booking the costs of the failed transformer to Account No. 353 and establishing a regulatory asset for the costs. (Ex. 123 at 18-19).

306. Staff recommends placing the Higgins Station failed transformer costs into a regulatory asset, with carry, pending the outcome of litigation regarding the failed transformer. Because Nevada Power is engaged in litigation activities, there is a possibility that Nevada Power will be awarded monetary damages regarding the failed transformer. If so, Nevada Power could credit the settlement amount back against the costs of this project; but, it would still be over-recovering and earning a rate of return on the full project costs during the time between receipt of the next general rate case because rates would have been set including the full project costs. (Ex. 136 at 12-14).

307. Staff states that if Nevada Power puts the transformer replacement project into a regulatory asset account and then must bring the resolution of the issue forward for prudency review in a future

docket, it would provide assurances that Nevada Power would vigorously pursue all legitimate legal options to recover any damages it may be entitled to, which would then offset the project cost equitably between ratepayers and Nevada Power. (Ex. 136 at 14).

Rebuttal

308. Nevada Power disagrees with Staff's and BCP's proposed adjustments. The replacement transformer was prudently procured and installed and is presently providing service to customers. The transformer's replacement costs should be placed into rate base. Neither BCP nor Staff suggested that the costs of the project were imprudently incurred or that management of the project was unreasonable. BCP specifically states that Nevada Power did not cause the damage to the failed transformer through any actions or inactions. When, or if, Nevada Power is successful in litigation regarding the failed transformer, those proceeds will be appropriately returned to ratepayers. (Ex. 154 at 18-19).

PUCN Discussion and Findings

309. The PUCN accepts Nevada Power's request to place the Higgins failed transformer costs into rate base. The transformer is installed and is used and useful. There is no evidence in the record supporting a position that the cost for the transformer was not prudently incurred. However, addressing Staff's and BCP's concerns, the PUCN requires Nevada Power to establish a regulatory asset account for the net book value of the failed Higgins transformer that will accrue carrying charges until the time of the next general rate case. Any proceeds received from litigation or from insurance claims should be credited against the regulatory asset.

b. Condensate Pump System Plant Adjustment and Related Depreciation Expense

Party Positions

310. Nevada Power requests recovery of $1,422,708 for Higgins condensate pump upgrades. The condensate pump upgrade project was performed to replace the original condensate pumps because of a continuous vibration issue with the pumps. After subsequent engineering review, it was determined that the original pump designs and respective hydraulic flow analyses did not properly address the various operating scenarios that are performed as the Higgins is cycled up and down to meet requested load. The original equipment was designed for baseload operation. After reviewing the options, Nevada Power determined that it was more efficient and cost-effective to replace the original pumps rather than continuing to make mechanical modifications to the existing pumps. The new pumps are designed with the actual Higgins's operating condition in mind, will reduce maintenance costs, deliver more efficient pump performance, and reduce the risk for plant availability loss. (Ex. 154 at 90-91).

311. BCP recommends disallowing recovery of $1.316 million that Nevada Power expended to replace the Higgins Station condensate pumps. The Higgins pump replacement project provides

inadequate return on investment to ratepayers, and Nevada Power's reasons for replacement (reliability and efficiency) do not warrant expenditures with a 37-year payback period. (Ex. 123 at 15-16.)

Rebuttal

312. Nevada Power argues that BCP relies upon a business case that contains errors and incorrectly lists the payback period for the Higgins pumps project as 37 years. Rather, the correct business case shows the payback period at 6 years. (Ex. 154 at 24).

PUCN Discussion and Findings

313. The PUCN finds that Nevada Power's requested amount for the Higgins pumps replacement project is reasonable. BCP's proposed adjustment is based on a business case that contains errors. New pumps are designed with Higgins's operating conditions in mind, will reduce maintenance costs, deliver more efficient pump performance, and reduce the risk of plant availability loss.

c. Digital Control System Upgrade and Related Depreciation Expense

Party Positions

314. Nevada Power requests recovery of $4,346,568 for the Higgins integrated plant digital control system upgrade project. The digital control system upgrade project was specified and performed to replace the original electronic digital control systems platforms because the systems exceeded their useful lives and presented reliability risks to the Higgins Station plant. Replacing the existing platforms with an integrated platform adds benefits through better control integration, a single operator interface, an integrated alarm management system, and a single point of contact for technical and equipment support. (Ex. 81 at 91-92).

315. BCP recommends disallowing $5.156 million for the Higgins plant digital control system upgrade project. BCP states that Nevada Power did not provide adequate justification for the expenses and that the existing digital system was operational. The return on investment for this project is much lower than the ROE, which is not fair to ratepayers. (Ex. 123 at 16-17).

Rebuttal

316. Nevada Power disagrees with BCP's recommended disallowance because the reason for the digital control upgrades is that the hardware and software platforms for the Higgins steam turbine and combustion turbine controls were approaching obsolescence. The digital systems also had limited support from their manufacturers due to their age. (Ex. 154 at 25-26).

317. Nevada Power contends that the payback period was only one consideration of many that Nevada Power used to evaluate the digital control system upgrade project. In the case of control systems, it is very likely that if Nevada Power were to experience a negative event, it would be during a peak period. During peak periods, replacement costs are so high that this project could have been

justified on the basis of a single event. Because the consequences of the failure at peak are so high, Nevada Power had to look not only at payback period, but also at the consequences of a failure during peak. After evaluating the risks, Nevada Power chose to complete the digital control system upgrade. (Ex. 154 at 26-27).

PUCN Discussion and Findings

318. The PUCN finds that the $4,346,568 cost for the Higgins integrated plant digital control system upgrade project was reasonable. The upgraded digital control system significantly improves the functionality of the control systems at Higgins, and its existing system was approaching obsolescence.

2. Lenzie Generating Station Retirements

Party Positions

319. Nevada Power has started to make retirements to the original equipment that was installed as part of the Lenzie combined cycle units. (*See* Ex. 140 at 13; Ex. 145 at 2-5).

320. Staff recommends removing the cost of retired plant from the Lenzie combined cycle plant balance that is eligible for the critical facility enhanced ROE. Staff discovered that Nevada Power has started to make substantial retirements to the original equipment that was installed as part of the Lenzie plant's combined cycle units. The PUCN designated the Lenzie units as a "critical facility" in Docket No. 04-6030, and thus, the Lenzie units are eligible for an enhanced ROE that includes an additional 2.5 percent above their authorized ROE. Besides the cost savings for ratepayers, making Nevada Power remove the cost of retired plant from the Lenzie combine cycle plant balance that is eligible for the enhanced ROE also incents Nevada Power to maximize the useful life of the original equipment installed on the Lenzie units. (Ex 140 at 3, 16-17).

Rebuttal

321. Nevada Power states that it disagrees with Staff's proposal and calculations. Nevada Power purchased the Lenzie facility as a result of the Western Energy Crisis, which emphasized Nevada's short position and exposure to the wholesale energy market. Despite Nevada Power's weakened financial condition, Nevada Power was able to acquire the Lenzie facility and reduce the State's vulnerability to the wholesale market, but only because the PUCN awarded the Lenzie facility "Critical Facility" status. With that designation, which included recovery for O&M and depreciation between rate cases and a modest ROE incentive, Nevada Power was able to finance the acquisition and weather regulatory lag. Nevada Power asserts that Staff's proposal is a rescission of the regulatory compact. (Ex. 145 at 2).

PUCN Discussion and Findings

322. The incentives adopted by the PUCN in Docket No. 04-6030 relating to the Lenzie facility were not intended to continue after Nevada Power replaced the equipment there. Accordingly, the PUCN approves Staff's proposed reduction to plant in service by the amount of the retirements at Lenzie. In doing so, the PUCN approves the accounting methodology contained in Nevada Power's rebuttal testimony. Nevada Power must remove the value of the retired plant eligible for enhanced ROE from the plant in service as it was calculated by Nevada Power witness Melo. Account No. 101 should be reduced by the amount of the retirements at Lenzie. These corrections reduce the accumulated provision for depreciation.

3. Goodsprings Generating Station Restoration

Party Positions

323. Nevada Power seeks recovery of approximately $6.5 million in costs related to the restoration of the Goodsprings Generating Station. The Goodsprings restoration project included the replacement of the waste heat oil heater tube bundles, installation of isolation plates to control hot gas flow in the waste heat oil heater, installation of instruments to monitor tube and oil temperatures and modification of plant controls, and replacement of thermal transfer fluid.

324. Nevada Power states that the restoration project was necessary to return Goodsprings to safe, reliable service and to address original design issues that presented operational and reliability risks. The Goodsprings restoration project went over budget by 7.69 percent and operated behind schedule; however, Nevada Power states that the project was prudently designed and constructed and that the costs were prudently incurred. Since returning to service in April 2016, the plant has been operating with an availability factor of 94.7 percent. (Ex. 81 at 46, 49, 51).

325. BCP recommends disallowing $6.1 million in Goodsprings restoration project costs. BCP states that the design of the plant was a collaborative effort between Nevada Power and Ormat, Inc. Given the size of the modification and the operational history of Goodsprings, BCP states that the restoration project was a research and development project that was not presented to the PUCN. Ratepayers should not be held responsible for the costs of a plant modification that was poorly designed and has all of the appearances of a research and development project. (Ex. 123 at 5-6).

326. Staff recommends disallowance of one-half of Goodsprings restoration project costs. Staff states that it is making its recommendation due to Nevada Power's imprudent oversight of the design, construction, and operation of the Goodsprings restoration project. Ratepayers should not be required to cover 100 percent of the costs of Nevada Power's imprudent management. (Ex. 138 at 1-2).

327. Staff explains that between 2011 and 2016 Goodsprings produced only 42 percent of its expected production. Goodsprings experienced numerous forced outages between 2011 and 2016 due to issues with the fire protection system, automation controls, turbine bearings, and the thermal oil fluid. It is not reasonable for ratepayers to pay for the entire Goodsprings restoration project with these improper design, construction, and operational issues.

328. Although Staff agrees that Nevada Power did not properly oversee the design, construction, and operation of Goodsprings, Staff recognizes that the Goodsprings restoration project does provide Nevada Power's ratepayers with some benefits, including a source of lower-cost energy that is not subject to fuel price volatility. Additionally, the Goodsprings restoration project creates renewable portfolio credits. Based on these considerations, Staff suggests that splitting the costs between Nevada Power's shareholders and ratepayers is a reasonable outcome for the costs and benefits of the restoration project. (Ex. 138 at 2-5, 10-13; Tr. at 1270-1273).

Rebuttal

329. Nevada Power disagrees with BCP and Staff's recommendations. Nevada Power states that the Goodsprings restoration project should be considered a prudent investment. Goodsprings has performed better than ever. Goodsprings was not originally designed to an inferior standard, rather, the plant is very similar in design to many other heat recovery plants that Ormat has built. Nevada Power does not agree that design defaults were overlooked. Overheating of heat exchangers is common. These faults were not known until Goodsprings was put in service. The restoration at Goodsprings installed new controls and monitors to monitor the tubes in the heat exchanger. (Ex. 154 at 10, 16; Tr. at 1489-1497). Nevada Power rebuts BCP's statement that the Goodsprings restoration project was a research and development effort between Ormat and Nevada Power. It was designed and built similarly to other compressor station heat recovery plants at the time. (Ex. 154 at 10).

PUCN Discussion and Findings

330. The PUCN accepts Staff's proposal to disallow half of Goodsprings restoration project costs. Goodsprings experienced forced outages between 2011 and 2016 due to issues with the fire protection system, automation controls, turbine bearings, and thermal oil fluid. It appears, at least in part, to be a troubled project. It is not reasonable for ratepayers to pay for the entire Goodsprings restoration project with these improper design, construction, and operational issues.

331. Yet, despite its flaws, the PUCN finds that the Goodsprings restoration project does provide Nevada Power's ratepayers with some identifiable benefits, including a source of lower-cost energy that is not subject to fuel price volatility. It adds to Nevada's overall renewable energy portfolio and

creates renewable portfolio energy credits. Splitting the costs between Nevada Power's shareholders and ratepayers is a balanced and fair outcome.

4. Goodsprings Generating Station and Higgins Generating Station Paving Costs

Party Positions

332. Nevada Power paved with asphalt the Goodsprings and Higgins plant sites for worker safety. (*See* Ex. 138 at AED-15).

333. BCP recommends disallowing recovery of $1.6 million in costs related to paving roads at both Goodsprings and Higgins. BCP argues that the upgrades were unnecessary and the safety concerns are unsupported. The roadways at the plants had been in operation without improvement for years (5 years for Goodsprings and 15 years for Higgins) without any major incidents. (Ex. 123 at 2, 16-18).

334. Staff recommends disallowing the pavement costs at Goodsprings and Higgins because the expenditures were unnecessary. At Higgins, there was sufficient asphalt coverage for plant personnel to get around without the paving upgrades. Neither the original plant owners nor Nevada Power in the previous 12 years believed it was necessary to add more asphalt. Nevada Power could not identify a single incident at Higgins that could have been prevented by the additional paving performed during the recent asphalt upgrade. (Ex. 136 at 14-19; Ex. 138 at 13; Tr. at 1270, 1273-1276, 1281). At Goodsprings, Nevada Power paved the entire site with asphalt. Staff argues that this was unreasonable and that the costs should not be included in rates. (Ex. 136 at 14-19; Ex. 138 at 13).

Rebuttal

335. Nevada Power disagrees with Staff's and BCP's recommendations to disallow paving costs at Goodsprings and Higgins and states that such a disallowance would fail to recognize the importance of workplace safety. Paving is beneficial to the safe and reliable operation of generating units. With respect to the argument that no serious accidents have occurred, the PUCN should avoid setting the precedent that an investment in safety is only a prudent after an accident. (Ex. 154 at 20-22).

PUCN Discussion and Findings

336. The PUCN finds that paving the Higgins and Goodsprings sites are somewhat questionable and may push the bounds of reasonableness to the edge. But they do not cross it. Paving does have benefits to the safe and reliable operation of generating units. These costs are approved. However, Nevada Power should not interpret approval of these projects as a 'green light' to pave everywhere.

5. ERCR Replacement Capacity Regulatory Asset Amortization

Party Positions

337. Pursuant to the retirement of coal-fired generating capacity in Nevada, Nevada Power acquired new capacity. Nevada Power acquired LV Cogen (272-MW) and Sun Peak (210-MW) pursuant to the

ERCR plan approved in Docket No. 14-05003. Nevada Power also purchased Southern Nevada Water Authority's 25-percent ownership interest in the Silverhawk Generating Station (54-MW) and constructed the Nellis Solar Array 2 (15-MW).

338. Nevada Power established a regulatory asset to track the expenses associated with its acquisition and construction of the replacement capacity, with carrying charges accruing in accordance with NRS 704.7317 (Ex. 81 at 14-18). Nevada Power requests recovery of the deferred depreciation expense, return on its investment in the facilities, operations and maintenance expenses, as well as accrued carrying charges through rates to be established in this case. The amounts in the regulatory asset account and proposed amortization periods are as follows:

- LV Cogen: $90.722 million amortized 15 years ($6,048,000 annually);
- Sun Peak: $15.610 million amortized 6 years ($2,602,000 annually);
- Nellis Solar 2: $9.411 million amortized 21 years ($448,000 annually);
- Silverhawk: $0.489 million amortized 6 years ($81,000 annually).

(Ex. 3 at 180-186; Ex. 70 at 118-125; Ex. 81 at 19).

339. SEA proposes to amortize ERCR replacement capacity regulatory asset over the next three-year rate-effective period. Amortizing over the shorter period will (1) eliminate these regulatory assets from rate base in the subsequent rate case and (2) will ensure that these regulatory assets do not become stranded assets if the Energy Choice Initiative is approved and Nevada deregulates its retail market. (Ex. 49 at 39).[17]

340. Staff does not recommend the long amortization periods Nevada Power has proposed for the costs of the four power plants be included in the ERCR replacement capacity regulatory asset. These regulatory asset costs should be amortized over a three-year period. (Ex. 140 at 6).

341. Staff notes that Nevada Power set the amortization periods not based upon the remaining lives, but instead used the amortization periods as a rate mitigation tool to offset other costs, mainly the coal retirement costs. This is not an appropriate rationale for an amortization schedule. It is also inappropriate to take the O&M costs (mainly salaries), which were incurred, and should have been paid for by ratepayers, during the last two years, and make the next 15 to 21 years of ratepayers pay

[17]SEA's proposal to shorten the amortization period appeared to apply to both the ERCR replacement capacity regulatory asset and to the acquisition costs of the ERCR replacement assets. (Ex. 49 at 39). During the hearing, SEA clarified that its accelerated amortization proposal applies only to the ERCR replacement capacity regulatory asset amortization schedule and not to the amortization of the ERCR plant acquisition costs. (Tr. at 930).

for those costs with interest. Additionally, Nevada Power's proposed long amortization periods compound the stranded assets problem on the eve of the possible passage of the ECI. (Ex. 140 at 4-8.)

342. Staff also argues that increased annual amortization amounts will exert an upward pressure on revenue requirement and rates. (Ex. 140 at 9).

Rebuttal

343. Nevada Power contends that depreciation and amortization adjustments achieved by extending periods of amortization are not simple deferrals that do not harm Nevada Power financially, they also help to mitigate rate increases by reducing the revenue requirement impact on the immediate filing. (Ex. 142 at 13). Nevada Power explains that, with the exception of Silverhawk, it chose the amortization periods based on the approximate remaining book lives of the power plants, rounded to the nearest three-year rate cycle. Given its relatively small size, Nevada Power chose the standard two-rate cycle for Silverhawk. As long as the ERCR regulatory assets are afforded rate base treatment, Nevada Power wishes that the amortization periods selected for the full complement of ERCR regulatory assets would not lead to an increased revenue requirement. (Ex. 142 at 29-30).

PUCN Discussion and Findings

344. The PUCN finds that 6 years is an appropriate and reasonable period of time over which to recover the costs embedded in the ERCR replacement capacity regulatory asset. A 6-year amortization period offers the optimal balance between competing considerations of rate mitigation and timely cost recovery. The PUCN notes that a 6-year amortization period already matches the amortization periods that Nevada Power proposed for Sun Peak and Silverhawk regulatory asset costs recovery. Therefore, only the amortization periods for LV Cogen and Nellis Solar 2 shall accelerate in this case.

6. Carrying Charges on ERCR Replacement Capacity Regulatory Asset

Party Positions

345. Nevada Power established a regulatory asset to track the expenses associated with its acquisition and construction of the ERCR replacement capacity, with carrying charges accruing, pursuant to NRS 704.7317. (Ex. 81 at 14-18). Nevada Power requests recovery of the carrying charges associated with the ERCR replacement capacity. (Ex. 3 at 180-186; Ex. 70 at 118-125).

345A. FEA recommends removing from rate recovery the carrying charges associated with the ERCR replacement assets because (1) Nevada Power has been over-earning during the period in which carrying charges have been incurred; and (2) the PUCN has not specifically found that customers must pay a return on the decommissioning and remediation deferred costs. (Ex. 117 at 14-15, Attachment Gorman Direct-25).

PUCN Discussion and Findings

346. Similar to the issue of carrying charges associated with the Reid Gardner regulatory asset, the PUCN finds that the provisions of NRS 704.7317 and the previously-approved ERCR plan entitle Nevada Power to recover carrying charges associated with the ERCR capacity replacement regulatory asset. FEA's argument for denying recovery of the carrying charges based on Nevada Power's over-earnings does not cite to Commitment 4 established in the MidAmerican acquisition Docket No. 13-07021, which states that "normal rate case rules and procedures" would apply to "costs and revenues, and any under or over earnings would accrue to the Nevada Utilities until the next rate case filings."

D. ON LINE

Background

347. The One Nevada Transmission Line (ON Line) is a 231-mile, 500-kV transmission line, along with fiber optic communication facilities, that interconnects Nevada Power's and Sierra Pacific's electrical systems. ON Line's northern terminus is located near Ely, Nevada, and its southern terminus is at the Harry Allen Substation, northeast of Las Vegas, Nevada. The transmission line has the initial transfer capacity of 600 MW. ON Line was placed into service on December 31, 2013. ON Line was constructed through a joint venture between Nevada Power, Sierra Pacific, and Great Basin Transmission South, LLC (Great Basin). Great Basin is a 75-percent co-owner of ON Line, with Nevada Power owning 23.75 percent and Sierra Pacific owning the remaining 1.25 percent. Nevada Power and Sierra Pacific are currently leasing Great Basin's 75-percent interest. (Ex. 92 at 4-6).

348. On June 29, 2012, ON Line tower structures suffered damage due to wind-induced vibration. The stipulation approved in Docket No. 14-05004 resolved the ratemaking treatment for all costs to repair damage to the ON Line facilities as a result of the wind-induced event. Thirty (30) percent of the costs related to the wind-induced event became non-recoverable through rates. Seventy (70) percent of the aggregated repair costs, $43.738 million, were to be recovered through retail rates; 25 percent through inclusion in rate base and depreciation; and 75 percent through inclusion in expense representing annual lease payments to Great Basin. Nevada Power and Sierra Pacific agreed to defer the ON Line regulatory asset, approved in Docket No. 12-12031, for the portion of the lease payments representing costs incurred by Great Basin to repair the damage from the wind-induced vibration.

1. Regulatory Asset Carrying Charge

Party Positions

349. Nevada Power requests that the ON Line regulatory asset to be included in rate base and amortized in the current filing also includes additional ON Line project costs completed since the May

31, 2014, certification date in the last general rate case in Docket No. 14-05004. The regulatory asset amount of $35.831 million includes $7.221 million in carrying charges. (Ex. 92 at 9-13; Ex. 70 at 130.)

350. FEA recommends that $7.221 million in carrying charges added to the ON Line regulatory asset during the current rate-effective period (2015 through 2017) be excluded from rate recovery because revenues collected during the current period are sufficient to pay these carrying charges. (Ex. 117 at 14-15, Exhibit Gorman-Direct-25).

Rebuttal

351. Nevada Power disagrees with FEA's over-earnings calculations. The quarterly earnings reports cannot be relied upon for purposes of determining whether Nevada Power was in an excess earnings position for any year since the last general rate case. Significant regulatory assets are not considered in the quarterly earnings calculation. The quarterly earnings calculations are based upon the return on rate base, which excludes all regulatory assets established since the prior general rate case. Ignoring the impact of significant regulatory asset balances in the quarterly earnings reports overstates the ROE and should not be used as a basis for excluding recovery of some regulatory asset balances and/or carrying charges accrued on those balances. (Ex. 142 at 2-9; Ex. 41 at 1-6).

352. Additionally, Nevada Power argues that FEA's proposal to retroactively exclude regulatory asset balances and carrying charges on the basis of excess earnings from rate recovery violates Commitment 4 of the stipulation approving the MidAmerican acquisition. Commitment 4 states that "normal rate case rules and procedures" would apply to "costs and revenues, and any under or over earnings would accrue to the Nevada Utilities until the next rate case filings." (Ex. 142 at 39; Docket No. 13-07021 Order issued on December 17, 2013, at 25).

PUCN Discussion and Findings

353. The PUCN finds that Nevada Power's request to accrue carryings charges associated with the ON Line regulatory asset is reasonable and consistent with its decision in Docket No. 13-07021. Again, FEA overlooks this prior decision.

2. Cost Allocation between Nevada Power and Sierra Pacific

354. All parties agree that the appropriate forum to revisit the ON Line cost allocation between Nevada Power and Sierra Power should occur in the context of an IRP proceeding. The PUCN agrees with this conclusion. Any re-opening of the ON Line cost allocation should occur with notice and an opportunity for all stakeholders to participate. It should also involve a holistic inquiry. Accordingly, the current ON Line cost allocation will not be addressed further in this case.

D. VARIOUS CARRYING CHARGES ISSUES

1. Regulatory Asset Carrying Charges in Other Dockets

Party Positions

355. Nevada Power requests that the regulatory asset established for the voltage and volt-ampere reactive control and optimization (VVO) and conservation voltage reduction (CVR) project established in Docket No. 12-10013 be included in rate base at the May 31, 2017, balance and amortized over six years. Nevada Power requests that additional costs expected through October 16, 2017, be allowed continued deferral treatment in the regulatory asset. (Ex. 85 at 32-34; Docket No. 12-10013 Order issued on April 9, 2014, at 14-15).

356. The objective of the VVO Pilot Program was to determine the effectiveness of VVO/CVR at reducing electrical demand and energy consumption. The project was placed in service at a cost of approximately $3.2 million, including carrying costs. (Ex. 85 at 33-34.)

356A. Nevada Power requests that the regulatory asset established in Docket No. 12-05003 for the Non-standard Metering Option (NSMO) Trial Opt-Out Program Stranded Costs be included in rate base and amortized over six years. The NSMO regulatory asset was approved in the PUCN's Order in Docket no. 12-05003 and has a balance of $839,000, which includes program costs and carrying costs. (Ex. 106 at 28).

357. Nevada Power requests that the regulatory asset for Network Upgrades for Renewable Sources (NURS) approved in Docket No. 13-06002 be included in rate base and amortized over six years. The regulatory asset has a balance of $1.315 million, including infrastructure and carrying charge costs. The transmission system upgrades to Sierra Pacific's system were necessary to provide generation from four renewable sources in Sierra Pacific's service territory for purposes of meeting Renewable Portfolio Standard (RPS) requirements. In Docket No. 13-06002, the PUCN assigned the transmission upgrade costs to Nevada Power, stating that Sierra Pacific customers should bear no responsibility for upgrade costs necessary for Nevada Power to meet its RPS requirements. In Docket No. 14-05004, the PUCN reclassified the network upgrade costs and carrying charges from Sierra Pacific to Nevada Power. (Ex. 115 at 15-17; Ex. 3 at 177).

358. FEA recommends that carrying charges deferred in each of the three approved regulatory asset accounts be excluded from rate recovery as follows:

Regulatory Asset	Deferred Carrying Charges
NURS	$277,000
VVO	$495,000
NSMO	$58,000

The exclusion is warranted because Nevada Power earned in excess of its rate of return during the period 2015 through June 2017 and has had sufficient revenue to cover the carrying charge during the current rate-effective period. Excluding the carrying charge from rate recovery will avoid a scenario in which customers pay the carrying charge twice. Nevada Power has previously acquiesced to a regulatory approach that is symmetrical in equitably distributing returns between all stakeholders. (Ex. 117 at 12-16, Exhibit Gorman-Direct-25).

Rebuttal

359. Nevada Power observes that FEA bases its recommendation to exclude carrying charges from rate recovery for the three regulatory assets on the same argument it has used for other regulatory assets—excess earnings during the current rate-effective period produced sufficient additional revenue to cover the carrying charges accrued to these regulatory assets. As previously argued, if all regulatory assets subject to rate recovery in the next general rate case had been recognized in the quarterly earnings calculations, any excess earnings reflected in the quarterly reports would have been significantly reduced. (Ex. 41 at 1-6; Ex. 142 at 2-7).

360. Moreover, the stipulation approved in the MidAmerican acquisition Docket specifies that any under- or over-earnings during the period prior to the next GRC accrue to the Nevada utilities. FEA's recommendation to exclude carrying charges accrued to approve regulatory assets based upon alleged excess earnings violates the stated intent of the stipulation approved in Docket No. 13-07021. (Ex. 142 at 38-39). Contrary to FEA's assertion that carrying charges have not been expressly authorized, regulatory assets for NURS and NSMO are among those established in conjunction with Sierra Pacific and have already been adjudicated to accrue carrying charges. The only regulatory asset that applies exclusively to Nevada Power is the one established for VVO. (Ex. 142 at 39-40).

PUCN Discussion and Findings

361. The PUCN grants Nevada Power's request for rate base recognition and a six-year amortization period for the regulatory assets, including corresponding carrying charges, established for VVO, NSMO, and NUSF projects. The PUCN has already provided for the deferral of carrying charges in the regulatory assets in Docket Nos. 12-10013 (VVO) and 13-06002 (NURS). (Docket No. 12-10013, Order issued on April 14, 2014, at 3, attached Report at 14-15; Docket No. 13-06002, Order issued on February 4, 2014, at para. 374.) For its share of the NSMO trial program costs, Nevada Power obtained a carrying charge authorization in conjunction with Sierra Pacific in Docket No. 13-06002, Order issued on February 4, 2014, at paragraph 374, as reported by Nevada Power.

2. Cancelled Integrated Resource Plan (IRP) Projects Regulatory Liability Carrying Charges

Party Positions

362. Nevada Power requests a regulatory liability of $2.729 million to recognize the cost of equipment and materials from cancelled projects that received regulatory asset treatment in Docket No. 14-05004. Nevada Power proposes to amortize it over a three-year period. (Ex. 85 at 31-32).

363. Staff states that because these regulatory assets have been receiving a rate of return, the regulatory liability for equipment and materials transferred from the regulatory asset accounts to other projects should receive a carrying charge. (Ex. 127 at 8-9). Staff recommends that the PUCN approve Staff's calculation of the carrying charges in the amount of $402,002. As calculated, these carrying charges decrease rate base by the same amount, decrease the amortization expense by $134,000, and lead to an ADIT adjustment of $140,700.

Rebuttal

364. Nevada Power argues that it has not proposed to calculate a carrying charge on the cancelled project regulatory liability. Nevada Power proposes to establish a contra-account to offset a regulatory asset that is in rate base. The contra-account reduces the balances in the respective regulatory asset and reduces return. Payment of a carrying charge for the regulatory liability would result in a double counting of the reduction in return. (Ex. 142 at 37).

365. With regard to the accuracy of Staff's calculations, Nevada Power notes that, while Staff correctly calculated the carrying charges in total, the carrying charges by function must be allocated to arrive at the Nevada Jurisdictional adjustment. As corrected, the carrying charges decrease rate base by $391,000, decrease the amortization expense by $130,000, decrease federal income tax by $46,000, and lead to an ADIT increase of $115,000. (Ex. 147 at 15).

PUCN Discussion and Findings

366. The PUCN adopts Staff's proposal to record carrying charges on the amount of Cancelled IRP Projects regulatory liability. The PUCN accepts Nevada Power's corrections to Staff's calculations. The PUCN finds that the amount of carrying charges should be limited to the period beginning with the date of the transfer of the $2.729 million in equipment and materials to December 31, 2017, the date used by Nevada Power to calculate carrying charges on regulatory assets. As long as the carrying charges are not added to the regulatory liability account after December 31, 2017, a double recognition of the carrying charge will not occur.

3. Carrying Charges on Three Settlement Payments to Nevada Power

Party Positions

367. Nevada Power states that it received settlement payments for two projects, the Commerce Substation Rebuild and the Crystal Autotransformer Replacement, as well as an insurance settlement payment for Reid Gardner. Settlement payments were received by Nevada Power in the amounts of $3,302,137 for the Commerce Substation Rebuild, $857,052 for the Crystal Autotransformer, and $6 million for the Reid Gardner insurance settlement. Carrying charges have not been calculated for these settlements. (Ex. 83 at 20-21; Ex. 85 at 18-19, 24; Tr. at 743-44, 747).

368. Staff recommends a carrying charge be established for the three settlement payments Nevada Power received for the Commerce Substation Rebuild and the Crystal Autotransformer Replacement, as well as the insurance settlement payment for Reid Gardner. Staff recommends the following amounts for the three settlement carrying charges and adjustments:

> •Commerce Substation Rebuild Settlement Payment: approve a carrying charge of $961,000;
>
> •Crystal Autotransformer Settlement Payment: approve a carrying charge of $249,000; and
>
> •Reid Gardner Insurance Settlement Payment: approve a carrying charge of $1,097,000.

(Ex. 127 at 3, 9-11; Tr. at 1148-1160).

Rebuttal

369. Nevada Power states that it does not agree with Staff's proposed carrying charges. Nevada Power states that the full value of the three settlement payments received were fully credited to the customers upon receipt. In the instance of the Commerce Substation Rebuild and Crystal Autotransformer settlement payments, payments of $3.3 million and $847,052 were booked as offsets to rate base. Staff calculates carrying charges of $961,000 and $249,000, respectively, on these payments. For the Reid Gardner insurance settlement payment, the $6 million settlement payment was directly and immediately booked as a reduction to the Reid Gardner decommissioning and remediation regulatory asset. Staff proposes to impute over $1 million in carrying charges for this almost simultaneous receipt of the settlement payment and reduction to the appropriate regulatory asset account. Customers saw no deterioration in the value of the settlement payments due to the time value of money—customers were credited with the settlement payments when Nevada Power received them. (Ex. 142 at 37-38; Tr. at 1372-73).

370. Nevada Power also states that it has other concerns with Staff's carrying charges proposals, including that the proposals are retroactive ratemaking and that the proposals result in a "claw back" of earnings realized since the close of the Mid-American acquisition. In the Mid-American acquisition, Docket No. 13-07021, the stipulation that the PUCN approved states that "normal rate case and procedures apply to costs and revenues, and any under or over earnings would accrue to the Nevada Utilities until the next rate case filings after 2014..." Staff's proposals, which deviate from normal ratemaking, violate that provision of the stipulation. (Ex. 142 at 37-38).

PUCN Discussion and Findings

371. The PUCN rejects Staff's proposed carrying charges for the Reid Gardner insurance settlement payment but approves Staff's recommended carrying charges for the Commerce Substation and Rebuild Crystal Autotransformer settlement payments. The $6 million Reid Gardner insurance settlement payment was included in the net book value that was transferred to a regulatory asset established in Docket No. 14-05003 and predated ERCR plan approval.

372. The Commerce Substation and Rebuild Crystal Autotransformer settlement payments were credited to the related plant accounts and have not received a carrying charge since Nevada Power received them. Staff's recommendation for carrying charges on these two settlement payments is justified for the following reasons. First, carrying charges have been consistently allowed on the deferral of costs in regulatory assets between GRCs to recognize that a utility will be denied recovery of and a return on these costs and/or investments until they are recognized in setting rates in a subsequent GRC. Second, Staff's recommendation is one of the consistent treatments for unusual revenues/settlement payments that occur between GRCs and will eventually be returned to customers in a future GRC. While regulatory liabilities are much less common than regulatory assets approved by the PUCN, regulatory liabilities do occur.

373. The fundamental question in this issue is whether customers should be given equal treatment when Nevada Power receives a significant revenue source—in this case settlements from third parties—between general rate cases. The PUCN believes customers should receive this fair and equal treatment. The only way for the equal treatment to occur for customers is for the PUCN to look back to the recent three-year rate-effective period and consider whether any significant additional revenue received should be treated as a regulatory liability when received with carrying charges until the next general rate case. Therefore, the PUCN approves Staff's proposed carrying charges for the Commerce Substation Rebuild settlement payment in the amount of $961,000, and $249,000 for the Crystal Autotransformer settlement payment.

4. Carrying Charges on Net Energy Metering (NEM) Liability

Party Positions

374. Nevada Power did not include a carrying charge on the regulatory liabilities established in Docket Nos. 15-07041 and 15-07042 for approval of cost-of-service studies and net energy metering (NEM) tariffs. (Ex. 3, I-CERT-28, at 114).

375. Staff recommends that a carrying charge be added to the regulatory liabilities established in Docket Nos. 15-07041 and 15-07042 for approval of cost-of-service studies and NEM tariffs. In Docket Nos. 15-07041 and 15-07042, the PUCN approved the establishment of a regulatory liability to ensure that customers receive the benefit of the approved NEM rate changes. The difference between what NV Energy would collect under the old NEM-1 rates and rules, and the new NEM rates and rules, would be tracked and recorded in a regulatory liability account from the effective date of the new rates until rates were again adjusted in the next GRC. The order in Docket Nos. 15-07041 and 15-07042 created a NEM regulatory liability, but it did not address whether a carrying charge should be calculated for the regulatory liability (Ex. 127 at 6; Tr. at 1145-1146).

376. Staff states that Nevada Power's NEM regulatory liability account continues to track the difference in revenue earned for the approximately 500 remaining non-grandfathered customers. Staff states that carrying charges for recovery of regulatory accounts should be consistently applied to both regulatory assets and liabilities. In this current case, Nevada Power has calculated carrying charges for regulatory assets, but not regulatory liabilities. Staff recommends adding carrying charges to the NEM regulatory liability account. Staff's calculation of carrying charges results in the following adjustments: a decrease of rate base by $627,000, an increase in other revenue by $209,000 for annual amortization, and an adjustment to accumulated and deferred income taxes, by $219,000, which increases rate base. (Ex. 127 at 7-8).

Rebuttal

377. Nevada Power states that the NEM regulatory liability that was established for both Sierra Pacific and Nevada Power in Docket Nos. 15-07041 and 15-07042 did not include a carrying charge. Adding a carrying charge for Nevada Power's NEM regulatory liability would be inconsistent with the treatment afforded Sierra Pacific in 2016, when Sierra Pacific had a general rate case that did not include a carrying charge for Sierra Pacific's regulatory NEM liability. (Ex. 142 and 36-37).

PUCN Discussion and Findings

378. The PUCN approves Staff's proposal and calculations for a carrying charge on Nevada Power's NEM regulatory liability. Customers and shareholders should be treated consistently when it comes to recognizing the time value of money and carrying charges for funds expended or received by a utility

during the rate-effective period between general rate cases. Fairness to both parties demands consistent treatment. The fact that the stipulation in Sierra Pacific Power's general rate case did not expressly address the NEM regulatory liability does not discount the need to treat regulatory assets and liabilities consistently in this case. Due to the give and take that occurs during a negotiated settlement, stipulations cannot be used as precedent for any issue. For these reasons, the PUCN approves Staff's proposal and calculations for a carrying charge on Nevada Power's NEM regulatory liability.

E. TAX ISSUES

1. The Federal Corporate Tax Rate Lowered During Rate Effective Period

Party Positions

379. Nevada Power uses the standard 35 percent federal corporate tax rate in its revenue requirement calculations. (*See* Ex. 3 at Statement H; *see also* Ex. 70 at Statement I).

380. MGM proposes that Nevada Power create a reserve account that retains tax savings from a possible reduction in the current marginal corporate tax rate. MGM notes that present revenue requirements are based on the current marginal corporate tax rate and that there is considerable talk nationally about reducing this tax rate. To the extent that this tax rate is reduced during the rate-effective period, creating a reserve account containing tax savings between the current and reduced tax rate would benefit further retirement costs associated with the coal plants.

381. MGM recommends that for the remainder of the rate-effective period, potential tax savings be shared between customers and shareholders at 50 percent each. (Ex. 118 at 8).

382. SNGG posits that if tax reduction savings do occur, a rate case could be brought immediately following the tax change or have a regulatory liability that would track the savings from the rate change and accrue it in a regulatory liability account, and then in the next rate case give it all back to ratepayers at the same time. (Tr. at 965).

383. BCP proposes that, in the event federal corporate income tax legislation is enacted that results in income tax expense savings during the ensuing three-year rate-effective period, Nevada Power should be required to calculate the amount of net expense savings realized and accrue such amounts, with carry, within a regulatory liability account. The methods and procedures for crediting such savings back to the retail cost of service can be determined in 2020. (Ex. 65 at 59).

384. BCP states that given the prevalence of deferral accounting authorized for Nevada Power for cost increases, it logically, equitably, and consistently follows that significant savings that may materialize as a result of changes in federal tax legislation should be deferred within a regulatory liability account for crediting to ratepayers in future rate proceedings. (*Id.* at 64). There should not be a corresponding adjustment to ADIT and rate base if an adjustment for a change in the federal tax

expense is made. ADIT is set at certification. If there are more permanent tax timing differences that are no longer deductible, BCP proposes it should fairly be considered in this calculation. (Tr. at 705).

Rebuttal

385. No rebuttal was submitted.

PUCN Discussion and Findings

386. The impact of any change in the federal corporate tax code was unknown at the time of the hearing in this case. Future, speculative savings are outside the statutorily-prescribed historical review period. *See* NRS 704.110. Reaching beyond the historical test year should occur only in the rarest of circumstances, and the PUCN finds that such circumstances have not fully materialized in this case.

387. Indeed, Nevada uses an historical test year adjusted for known and measureable changes at the certification date (within 6 months after the date of filing). *See* NRS 704.110(3). A utility may also file a statement of expected changes in circumstance for items reasonably known and measurable with reasonable accuracy that may occur within 210 days after the application is filed. *See* NRS 704.110(4). The revenue requirement calculation is based on historical data, or at the very least, information that is reasonably known and measurable within a statutorily-prescribed time frame. The intervening parties' recommendations would reach beyond the statutory time period and are based, at this point, upon something that has not occurred.

388. Even if it does occur, its effects on NV Energy are not known or measureable. Federal income tax expense is only one part of the federal tax impact to a utility in a general rate case. The intervening parties making their recommendations would appear to ask the PUCN to modify one element but ignore impacts to others. The PUCN declines to do so at this time on this issue standing alone.

2. Domestic Production Activities Deduction (DPAD) Adjustment

Party Positions

389. Nevada Power asserts that, despite no longer having a net operating loss, a Domestic Production Activities Deduction (DPAD) cannot be supported at this time when all tax timing differences are reflected in the calculation as required by the Internal Revenue Service (IRS) regulations. (Ex. 113 at 8-10). To calculate DPAD, the IRS requires Nevada Power to (1) derive generation taxable income and total taxable income using all book-to-tax differences and (2) multiply the lower of the two by the applicable deduction rate, which is nine percent. (Ex. 113 at 9). The method adopted in Docket No. 08-12002 for the approximation and imputation of DPAD should not be used here because that calculation was hypothetical and was meant to be replaced when Nevada Power actually filed with the IRS a tax return that included DPAD. (Ex. 113 at 8).

390. The DPAD calculation adopted in Docket No. 08-12002 reflects only two tax timing differences - depreciation and the Lenzie unit incentive—not all tax timing differences as required by the IRS, specifically, Treasury Regulation § 199(c)(1)(B). (Ex. 113 at 10-11). When Nevada Power accounts for all book-to-tax differences in calculating taxable income from generation,[18] no DPAD is available because net taxable income from generation is negative. (Ex. 113 at 10).

391. Staff explains that the DPAD is a deduction from taxable income created by the American Jobs Creation Act of 2004. Its purpose is to encourage domestic production activities and, thus, spur domestic job creation. (Ex. 139 at 12).

392. Staff recommends that a DPAD of $18.42 million be reflected in the calculation of the current income tax expense. This translates into a $6.447-million reduction in income tax expense and, consequently, a revenue requirement reduction of $9.918 million. (Ex. 139 at 11). Staff calculates the $18.42 million DPAD by following the applicable IRS regulations as Nevada Power has done; however, unlike Nevada Power, Staff calculates DPAD using a 12-month window for book-to-tax differences consistent with a 12-month tax period. That 12-month approach contrasts with the 29-month window that Nevada Power uses for the ERCR regulatory assets and the 15-month window for the NRS 704B impact fees regulatory liabilities. Additionally, Staff's DPAD calculation assumes multi-year Reid Gardner tax adjustment, rather than an all-at-once $141-million adjustment applied by Nevada Power. (Ex. 139 at 12). Staff notes that Nevada Power first calculated a $19.437-million DPAD for the test period but subsequently removed it as a Certification Adjustment. (Ex. 139 at 13).

393. BCP recommends that income tax expense reflect a DPAD based on the methodology proposed by BCP and accepted by the PUCN in Docket Nos. 08-12002 and 10-06001. (Ex. 65 at 64). BCP's recommendation reflects the same timing differences in calculating the DPAD as was proposed and accepted by the PUCN in Docket Nos. 08-12002 and 10-06001. BCP's proposed DPAD is approximately $14.357 million after reflecting rate base disallowances proposed by BCP. (Ex. 65, Attachment JRD-1 at 39).

394. BCP opines that Nevada Power's calculation of the DPAD in this case is seriously flawed for the following reasons:

> • Nevada Power's book-to-tax timing differences bear no resemblance to historical amounts for a *one year* period;

[18] These differences include a $59.56-million increase on account of NRS Chapter 704B impact fees and an approximately $240-million decrease on account of ERCR assets, including a $141.29-million decrease associated with Reid Gardner Unit 4 retirement.

> • The value of book-to-tax timing differences related to significant regulatory assets and liabilities on Nevada Power's books, resulting from prior PUCN decisions, bear no resemblance to the values that can be expected during the rate-effective period for this case; and
>
> •Nevada Power's proposed DPAD calculation employs the use of multiple years of book/tax timing differences, which would never be allowed for purposes of filing an annual tax return with the IRS.

(Ex. 65 at 68-70 (emphasis added)).

395. The book-to-tax timing difference used in the DPAD calculation by Nevada Power for impact fees received from Wynn, MGM, and Switch reflects a $47-million increase to book income in determining production taxable income. However, during the rate-effective period, the book-to-tax timing difference for impact fees will actually be a reduction to book income in determining production taxable income used for calculating the annual DPAD. (Ex. 65 at 77-80).

396. In calculating the DPAD, Nevada Power has also reflected an approximate $140-million deduction to book income in determining production taxable income related to Reid Gardner Units 1-4. Nevada Power's response to BCP discovery reflects that, during the rate-effective period, 2018-2020, Nevada Power actually expects the opposite effect on production taxable income for the book-to-tax timing differences resulting from the retirement of the Reid Gardner Units 1-4. Nevada Power's response to Data Request No. 3-07 reflects an approximate $55 million increase to book income in determining production taxable income. (Ex. 65 at 82-83, Attachment JRD-13 at 3).

397. With regard to the Las Vegas Cogen Units 1 & 2 regulatory asset, Nevada Power's calculation of the DPAD reflects an approximate $84-million reduction to book income in determining production taxable income. In contrast, Nevada Power's response to BCP discovery reflects the opposite impact on production taxable income—an approximate $6-million annual addition to book income during the rate-effective period. (Ex. 65 at 85).

398. Nevada Power's DPAD calculation reflects a similar result related to the book-to-tax timing difference for the Nellis Solar Generating Station and Sun Peak regulatory assets. Nevada Power's DPAD calculation reflects deductions to book income in the amounts of approximately $9 million and $13 million respectively. However, during the rate-effective period, Nevada Power will experience the opposite impact on production taxable income—these book-to-tax differences will increase taxable income by $447,000 and $2.6 million per year, respectively. (Ex. 65 at 85-86).

399. Nevada Power's proposal in the instant case is similar to Sierra Pacific's proposal in Docket No. 10-06001 to use book/tax timing differences, accumulated over multi-year periods, to eliminate

production taxable income for a one-year test period. This approach was rejected by the PUCN in Docket 10-06001 and should again be rejected in the instant docket. (Ex. 65 at 86-92).

400. SNGG recommends that the DPAD reducing income tax expense by $8.5 million in the Certification Filing, Statement P, be reflected in Nevada Power's cost of service in lieu of the $0 DPAD proposed by Nevada Power. (Ex. 50 at 37-38).

401. SNGG states that Nevada Power's witness admits in direct testimony that, "on a stand-alone basis, Nevada Power does not have a [net operating loss] as of December 31, 2016, and is not expected to show a loss for tax purposes for the certification period ending May 31, 2017." SNGG opines that, because Nevada Power qualified for a $19.4-million DPAD in 2016 and expects to qualify in 2017, the DPAD deduction should be reflected in rates set in this case. (Ex. 50 at 37-38).

Rebuttal

402. Nevada Power argues that none of the parties recommending a DPAD deduction in this case has provided any substantive evidence regarding the likelihood that Nevada Power will be able to take advantage of the DPAD during the rate-effective period. Whether Nevada Power will benefit from the DPAD during the rate-effective period is dependent on many factors, which are not known at this time, including (1) whether Congress enacts tax laws affecting DPAD, (2) the amount of Nevada Power's book income (or loss) in each tax year, and (3) the amount of other tax additions/deductions actually incurred in each tax year. (Ex. 144 at 2-4).

403. To ensure that Nevada Power's customers benefit from any potential DPAD that may be experienced in future years, Nevada Power proposes, as an alternative, setting a baseline DPAD of $3.6 million with a tracking mechanism that will capture annual differences between the base amount and the actual amount. The $3.6 million amount represents the benefit for DPAD Nevada Power reported on its 2016 filed tax return. This regulatory asset/liability mechanism will allow Nevada Power to correctly calculate DPAD according to IRS rules, without trying to estimate future generation tax deductions. (Ex. 144 at 3, 6-7, 10).

PUCN Discussion and Findings

404. The PUCN finds that a DPAD in the amount of $18.42 million, as proposed by Staff, should be adopted in the calculation of Nevada Power's income tax expense for ratemaking purposes. As stated by both Staff and BCP, Nevada Power's calculation of $0 DPAD erroneously employs the use of multi-year book/tax timing differences for the purposes of calculating *annual* tax filing values and fails to normalize tax events for the duration of the rate-effective period. (Ex. 139 at 11-13; Ex. 65 at 68-70). Nevada Power uses a 29-month period to value annual book-to-tax timing differences

associated with the ERCR acquisition assets (Ex. 139 at 12), and fails to normalize the $141-million reduction to production taxable income associated with Reid Gardner retirement (Ex. 113 at 10).

405. With respect to Reid Gardner retirement, Nevada Power's approach erroneously presumes that it will recognize this $141-million reduction to taxable income every year during the rate-effective period. (Ex. 139 at 12; Ex. 65 at 82-83). Staff's approach uses an annual period to value book-to-tax timing differences and normalizes tax events for the duration of the rate-effective period.

F. Operational Expenses and Miscellaneous Rate Base Items

1. Cost Savings from New Line Locate Service Provider

Background

406. Line locations are performed to prevent damage to subsurface installations, such as Nevada Power's underground electric installations. NRS Chapter 455 requires excavators to notify utilities in advance of any proposed excavation for the purpose of having potentially affected installations marked. This safety program is commonly known as "Call Before You Dig." Due to the volume of excavation notifications (tens of thousands annually), Nevada Power contracts out the line locate services to a third-party contractor. (Ex. 152 at 4-5).

Party Positions

407. Nevada Power has embedded in its filing $1,416,447 in line locating expenses and a $552,429 rate base addition for the services received from its previous line locate provider. (Ex. 131 at Attachment POL-3).

408. Staff recommends an $185,000 reduction to cost of service representing cost savings expected from a new line locating contract entered into on May 31, 2017—the end of the certification period for this case. Nevada Power awarded the new contract to USIC Locating Services, effective June 1, 2017. Staff's review of the specific pricing terms provided in the competitive bidding process indicates an expected annual savings from the new contract in the amount of $185,000. Removing these savings from the cost of service will avoid having the savings accrue to the benefit of Nevada Power's shareholders during the rate-effective period. (Ex. 131 at 1-4).

Rebuttal

409. Nevada Power contends that Staff's approach to estimating $185,000 in annual savings from the new line locating contract fails to compare the price per line location in the contract to the actual test year cost per line locate and, therefore, does not indicate whether the line location costs under the new contract will be higher or lower than those embedded in the test year. (Ex. 152 at 6-7). Staff's calculation was based upon a comparison of the per-unit bid price for the lowest and the next-lowest bidder participating in the bidding process for the new contract. This difference was multiplied by the

baseline of 60,898 line locates per year selected for the bidding process. (Ex. 152 at 5-6). Moreover, Nevada Power contends Staff's calculation also fails to recognize: (1) the test year flat rate per line locate was lower than the next-lowest bid used in Staff's calculation; and (2) pricing under the new contract escalates by three per year. (Ex. 152 at 7).

PUCN Discussion and Findings

410. The PUCN declines to implement the $185,000 cost adjustment proposed by Staff. Identification as to whether the new line location contract results in annual savings can only be made by comparing the cost per line locate in the new contract to the average cost per line locate in the 2016 test year O&M expense. Staff's approach to calculating the annual cost difference based on two bids provided during the contract bidding process is flawed. The result does not indicate whether the new contract will result in lower annual line locating costs than those reflected in the 2016 test year.

2. Capitalized Line Locating Costs

Party Positions

411. Nevada Power has embedded in its filing $1,416,447 in line locating expenses and a $552,429 rate base addition for the services received from its previous line locate provider. (Ex. 131 at Attachment POL-3).

412. Staff recommends that the PUCN disallow $552,429 of line locating costs from rate base, which results in a $12,872 reduction to depreciation expense (2.33-percent depreciation rate). Nevada Power failed to articulate the basis for assigning these costs to rate base. In response to Staff's request to identify the method for assigning line locating costs to rate base, Nevada Power stated that, "[b]ased on historical data, typically 20 percent of construction work after line locate service resulted in capital work." In this docket, however, Nevada Power assigned $552,429 of $1,260,653 (or 43 percent) of line locate costs incurred during the test year to rate base. Nevada Power also indicated that, due to the large number of inspections, line locating costs are not directly assigned to specific capital assets, but are rather aggregated and subsequently allocated to Plant-in-Service accounts. (Ex. 128 at 3-4).

413. Staff remains skeptical as to whether Nevada Power is entitled to capitalize costs that were not clearly incurred in the creation or betterment of revenue-generating assets. Nevada Power's policy of capitalizing line locating costs without assigning them to specific projects does not appear to Staff to be compliant with FERC accounting instructions either. Unlike overhead costs, which are expressly permitted to be generally allocated to rate base, line locating costs can be specifically identified and assigned as either capital or expense activities. (Ex. 128 at 4-5). Despite recommending exclusion of $552,429 of line locating costs from rate base, Staff argues against allowing recovery of these costs as Operations and Maintenance expense. Nevada Power has been benefiting from rate base treatment of

unassigned line locating costs since 2007. Therefore, Staff asserts that it is reasonable to disallow the amount embedded in rate base during the test year to correct the practice during the upcoming rate-effective period to compensate ratepayers for potential over-recovery in prior years. (Ex. 128 at 6).

Rebuttal

414. Nevada Power disputes Staff's attribution of the $552,429 line locate cost amount to Plant-in-Service. That amount represents the line locate service costs booked to Plant-in-Service for the latest general rate case period—June 2014 through May 2017. The actual amount of line locate costs booked to rate base during the test year is $178,068. That test year amount attributed to rate base represents 20.1 percent of the total line locate cost for the year: $178,068/$886,292 = 20.1 percent. This 20-percent ratio aligns exactly with the stated allocation methodology. (Ex. 152 at 11-12).

415. Nevada Power established the 20-percent allocation in 2007——when it began capitalizing line locate expenses. These capital costs have been included in rate cases since and have never been challenged by any party. The capitalization method is consistent with Electric Plant instructions of 18 CFR, Part 101 Section 13-Engineering Services, which provides that Engineering Services includes amounts paid to third parties "engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work."

415A. Drivers for performing line locating work are new business projects and line relocations driven by public works projects. Line locating activities end up supporting capital assets that Nevada Power owns and operates. (Ex. 152 at 12-13). Nevada Power contends that Staff has not presented any evidence that any of the line locating costs were imprudently incurred. Accordingly, even if Staff disagrees with Nevada Power's capitalization method, Staff should have asked the PUCN to treat these costs as an O&M expense, not to disallow them. (Ex. 152 at 10).

416. Nevada Power also argues that tracking line locate costs by specific project would be an unreasonably burdensome undertaking. Monthly bills from third-party vendors completing line inspections include thousands of sites and do not categorize locations by project type. (Ex. 152 at 14).

PUCN Discussion and Findings

417. The PUCN finds Nevada Power's inclusion of the $552,429 line locate cost allocation in rate base reasonable and well-supported. The allocation is a product of an established practice. Nevada Power's rebuttal is persuasive in explaining why the 20-percent allocation method is preferable to the case-by-case determination of whether a particular line locate job should either be expensed or capitalized. At the same time, Staff has not provided any directly-applicable authority that requires direct assignment of line locating costs to specific capital projects. Nor has Staff presented evidence, or even alleged, that Nevada Power imprudently incurred line locating costs.

3. Employee Performance Plans

a. Long-Term Incentive Plan

Party Positions

418. Nevada Power requests $3.8 million for recovery of the Long-Term Incentive Plan (LTIP) award in its revenue requirement. Most non-represented employees at the director-level and above are eligible to participate in the LTIP. LTIP payments are based on a corporate goals target of 100 percent and vary from year to year depending upon the achievement of company-wide goals, which are aligned with the same six core principles of the Short-Term Incentive Plan (STIP). LTIP awards are calculated using an eligible percentage associated with each job, ranging from targets of 20 percent to 125 percent. The LTIP is not paid to an individual employee unless corporate goals are met and the employee is rated as "performing well" or higher. Prior to Nevada Power's acquisition by Berkshire Hathaway Energy (BHE), LTIP awards were tied exclusively to shareholder earnings. Now that the transition to BHE LTIP is complete, including the portion of LTIP that is directly customer-driven in Nevada Power's revenue requirement calculation is appropriate and consistent with prior PUCN determinations. (Ex. 103 at 15, 23-24, 30, Ex. Oswald-Direct-2).

419. SEA recommends excluding Nevada Power's LTIP award from rate recovery. Nevada Power offers no evidence that LTIP benefits ratepayers other than pointing to its core principles. When asked to supply the goals and human resources documentation for employees under the plan, Nevada Power claimed such amounts were protected. This refusal to provide determination and rationale supporting the LTIP awards results in insufficient evidence to support inclusion of the LTIP in rate recovery. The additional LTIP compensation for executives is not required to motivate these executive employees to act on behalf of ratepayers. (Ex. 49 at 32-35).

420. SNGG recommends that 100 percent of the award under the LTIP be excluded from rate recovery, consistent with prior PUCN decisions. The PUCN disallowed Nevada Power's recovery of expenses associated with LTIP in Docket No. 08-12002. Moreover, other jurisdictions typically disallow LTIP compensation for executives/upper management. Many regulators are inclined to exclude incentive compensation from utility rates, understanding that these costs would be better borne by the shareholders. Just because these costs would be borne by the shareholders does not mean Nevada Power cannot award this compensation to its employees. (Ex. 50 at 33-35).

421. BCP recommends a $271,000 reduction in Nevada Power's requested LTIP award recovery. BCP makes two adjustments to the Customer Service section of Nevada Power's 2016 Corporate Scorecard, which is used to determine STIP and LTIP payout. First, BCP removed two irrelevant customer service survey results for the Sierra Pacific service territory. Second, BCP updated the

STIP/LTIP scorecard calculation to reflect results available for year-end 2016 instead of using forecasted goals that Nevada Power used. These adjustments reduced Nevada Power's Customer Service achievement rating from 9.6 percent to 3.36 percent. (Ex. 125 at 2, 3, 13, 15-16).

422. Staff recommends that the PUCN find Nevada Power's non-represented employees' LTIP reasonable, with two exceptions. First, the PUCN should deny $109,822 of the LTIP corresponding to a customer service metric in the year-end scorecard that was not met. While Nevada Power claims 89 percent of STIP and LTIP metrics were met, Staff does not agree. Exhibit Oswald-Direct 6 shows that the TQS large commercial and industrial key account metric was not met. Removing this metric places the STIP and LTIP achievement at 86.6 percent. This reflects the exact percentage that was earned based on the actual results of the year-end scorecard, not upon forecasted results. (Ex. 137 at 6, 8-12). Second, Staff states that the PUCN should also deny recovery of an additional $161,410 of the LTIP which was for an employee whose payroll costs are no longer included in revenue requirement. The Senior Vice President of Government & Communication Strategy was loaned to Edison Electric Institute at the start of 2017 and is no longer performing work on behalf of Nevada Power ratepayers. (*Id.* at 6, 8-12).

Rebuttal

423. Nevada Power agrees with Staff's recommendation to remove the LTIP award for a Senior Vice President now working as a loaned executive. However, Nevada Power made corrections to Staff's quantification and recommends the value for Staff's adjustment is $157,408 rather than $161,410. (Ex. 149 at 3). However, Nevada Power disagrees with SNGG's recommendation to exclude the LTIP award from rate recovery just because other jurisdictions disallow recovery. Nevada Power stresses that the design of its current LTIP is consistent with objectives outlined by this PUCN within this jurisdiction. The LTIP is based on goals and metrics designed to benefit customers. Nevada Power also states that prior PUCN decisions excluding the LTIP from rate recovery should be ignored in deciding the LTIP issue in this case. The BHE LTIP program bears no resemblance to the LTIP analyzed by the PUCN in Docket No. 08-12002. Prior to the BHE acquisition, LTIP awards were tied to return on investment. Additionally, SEA has provided no evidence that shareholder interests motivate executive-level employees. (*Id.* at 6-8).

PUCN Discussion and Findings

424. The PUCN finds that all of Nevada Power's LTIP award shall be excluded from rate recovery. The PUCN agrees with SEA's position that Nevada Power failed to provide sufficient evidence that it should recover in rates the costs of a program designed to incent executive level employees to act in the best interest of customers when those executives are already eligible to receive benefits under the

STIP, through which executive employees are eligible to earn up to 100 percent of their base salary. Nevada Power provides no evidence, other than pointing to the core principals of the program, to support including LTIP in revenue requirement. Notably, as stated by SNGG, barring recovery of LTIP compensation from the revenue requirement does not preclude Nevada Power from issuing LTIP awards to its employees.

b. Short-Term Incentive Plan

Party Positions

425. Nevada Power requests recovery of $3.96 million for additional compensation awarded to non-represented employees under its Short-Term Incentive Plan (STIP). Under this program, Nevada Power awards STIP payments, which vary annually, based upon individual performance and a set of specific company-wide goals: Customer Service; Employee Commitment; Environmental Respect; Regulatory Integrity; Operations Excellence; and Financial Performance.[19] These goals are measured through various residential and business surveys. STIP payments are only awarded to eligible employees with ratings of "performing well" or higher and range from five percent of base pay for non-exempt employees to 35 percent for executives. (Ex. 103 at 144, 151-162).

426. SNGG recommends that Nevada Power's requested recovery for STIP be reduced by $1.2 million to reflect a 50/50 sharing of the costs between ratepayers and shareholders. At least five other states require 50/50 sharing. Ratepayers assume the risk that rates will provide 100 percent of the recovery every year even though Nevada Power can fail to meet the plan's goals. SNGG's concerns with Nevada Power's 2016 scorecard results include: Customer Service performance being based on only a 50-percent expectation; performance under Customer Service does not justify Nevada Power's request for full recovery; safety and environmental goals benefit shareholders and should not be allocated 100 percent to customers; the Regulatory Integrity award is based upon completing routine regulatory filings and benefits shareholders at least as much as ratepayers; and any STIP award related to the "achievement of allowed ROE" under Regulatory Integrity is not a customer benefit. (Ex. 50 at 25-32).

427. BCP first recommends reducing Nevada Power's requested STIP recovery by $491,000. Removing two irrelevant customer service survey results for the Sierra Pacific service territory and updating the STIP/LTIP scorecard calculation to reflect results available for year-end 2016 results in this reduction to the requested STIP recovery. Notably, Nevada Power is using the August 2016 scorecard to determine STIP and LTIP payouts. Second, NV Energy should be directed to provide

[19] Nevada Power is not requesting the STIP award for Financial Performance metrics. (Ex. 103 at 32-33).

separate Customer Service Key Performance Indicators for the Sierra Pacific and Nevada Power service territories. NV Energy used combined survey results for the Sierra Pacific and Nevada Power service territories, a departure from prior practice. Third, NV Energy should be directed to provide Customer Service Key Performance Indicators on a final basis instead of on a forecasted basis for the test year. (Ex. 125 at 1-2, 7-16, Attachment PAM-10, Attachment PAM-11).

428. Staff recommends that the PUCN find Nevada Power's STIP reasonable, but with one exception. The PUCN should deny $96,161 of the STIP corresponding to a customer service metric in the year-end scorecard that was not met. While Nevada Power claims 89 percent of STIP and LTIP metrics were met, Staff does not agree. Exhibit Oswald-Direct 6 shows that the TQS large commercial and industrial key account metric was not met. Removing this metric places the STIP and LTIP achievement at 86.6 percent. This reflects the exact percentages that was earned based on the actual results of the year-end scorecard, not upon forecasted results. (Ex. 137 at 8-12).

Rebuttal

429. Nevada Power notes that NV Energy has improved in customer survey results following the 2016 test year. The 2017/2017 J.D. Powers residential survey indicates NV Energy is in the top 47 percent of comparable utilities. The Market Strategies International residential survey indicates an 83-percent satisfaction rate, and the commercial survey show s an 88-percent satisfaction rate. (Ex. 148 at 4). Nevada Power disagrees with BCP that the STIP scorecard for 2016 should be based upon the most current available results from each survey. NV Energy management should be allowed to determine the timing of surveys used to measure customer service metrics for the STIP. (Ex. 148 at 7-10). Nevada Power also states that discretionary compensation like STIP is an important piece of Nevada Power's total compensation package and is commonplace in the industry for attracting qualified employees. SNGG's proposal to allocate a significant share of the STIP costs to shareholders is not justified. NV Energy's goal to be in the upper 50 percent represents considerable improvements from prior years. (Ex. 149 at 5, 11-14).

PUCN Discussion and Findings

430. The PUCN approves BCP's recommendation to approve Nevada Power's requested recovery of $3.96 million for its STIP, with the exception of $491,000. This is reasonable. The PUCN agrees with BCP that STIP awards recovered in rates should be supported by survey results specific to Nevada Power's service territory in this Nevada Power rate case. The PUCN finds that Nevada Power's STIP awards should be based on the most currently available survey results. BCP updated Nevada Power's STIP scorecard calculation to reflect the actual results for 2016. These updated results show a reduction in Customer Service Core Principle achievement from 9.6 to 3.36 percent. (Ex. 125 at 15-

16). Therefore, it is only appropriate to reduce Nevada Power's requested recovery of STIP awards to reflect Nevada Power's customer service performance through the end of 2016.

4. Banner Database Upgrade and Data Analytics Platform Projects

Party Positions

431. Nevada Power seeks recovery of costs associated with two additional Information Technology projects—the Banner Database Upgrade Project and the Data Analytics Platform Project. Nevada Power acknowledges that its Application did not include these projects. Both projects were completed and placed in service during the certification period at the cost of $1,323,362 for the Banner Database Upgrade project and $1,106,366 for the Data Analytics Platform project. (Ex. 98 at 5).

432. Staff recommends a full rate base disallowance for both projects. Both of these projects, each valued in excess of $1 million, were identified in the certification filing, but were not identified in the direct filing. Rate base additions that occur during the 6-month certification period must be identified and be known and measurable at the date of the direct filing under NRS 704.110(3) and NAC 703.2461. Historically, Staff has recommended that certification additions with a value of $1 million or more should be identified in the direct filing in line with regulations. Nevada Power indicated that the failure to identify these projects in the direct filing was due to an internal error. (Ex. 132 at 7-9).

Rebuttal

433. Nevada Power maintains that both projects were prudently managed and placed in service in early 2017. These projects should not be excluded from rate base as a result of human error. Nevada Power identified the error in its certification testimony. (Ex. 151 at 2-3).

PUCN Discussion and Findings

434. The PUCN finds that the costs of the Banner Database Upgrade and the Data Analytics Platform projects should be included in Nevada Power's general rates. While the PUCN agrees with Staff that Nevada Power had an obligation to include the information about these two projects in its direct filing, under unique facts of these proceedings, disallowing cost recovery for the two projects would not further the goal of establishing just and reasonable rates. No party raised concerns with the prudency of the costs incurred in implementing these two IT projects. Thus, although Nevada Power failed to include the projects within its direct filing and, consequently, limited the time available for discovery on the issues they potentially raised, the omission did not hinder any party's efforts to obtain relevant information. Subsequent filings and noticing that occurred after the certification filing served to cure any procedural irregularity caused by Nevada Power's failure to include the costs of these projects in the direct filing.

5. Regulatory Asset for Rate Case Expense and Recovery of Regulatory Asset Costs

Party Positions

435. Nevada Power requests rate base recognition and a three-year amortization for two regulatory assets that include unrecovered costs incurred in the general rate case filing in Docket No. 14-05004 and its latest Integrated Resource Plan filing in Docket No. 15-07004. The regulatory asset balances for the prior general rate case and integrated resource plan filings total $962,000 and $309,000, respectively. (Ex. 74 at 14-15; Ex. 70 at 163-64). In Docket No. 11-06006, the PUCN agreed with Nevada Power and Staff that prudently-incurred rate case expenses, which could not be included in rates established in that case due to the timing of occurrence, should be deferred in a regulatory asset and recovered in the next general rate case. Rate recovery for costs incurred in filing an integrated resource plan is required under NRS 704.751(3). (Ex. 74 at 14-15; Docket No. 11-06006 Order issued on December 23, 2011, at 548-49).

436. FEA recommends that the regulatory assets requested by Nevada Power for rate base recognition and amortization including the $962,000 rate case expense and $309,000 in Integrated Resource Plan costs should be rejected. Nevada Power's revenues during the three-year period since the last general rate case have been more than adequate to cover the costs included in these two regulatory assets. FEA's review of Nevada Power's operating results from 2015 through June 2017 demonstrates projected over-earnings in excess of $158 million by the end of 2017. (Ex. 117 at 11-14). FEA further notes that the PUCN did not issue an order specifically authorizing regulatory asset treatment for the costs incurred in filing the 2014 general rate case or the 2015 integrated resource plan. (Ex. 117 at 13).

Rebuttal

437. Nevada Power disagrees with FEA's over-earnings calculations. The quarterly earnings reports cannot be relied upon for purposes of determining whether Nevada Power was in an excess earnings position for any year since the last general rate case. Significant regulatory assets are not considered in the quarterly earnings calculation. The quarterly earnings calculations are based upon the return on rate base, which excludes all regulatory assets established since the prior general rate case. Ignoring the impact of significant regulatory asset balances in the quarterly earnings reports overstates the return on equity and should not be used as a basis for excluding recovery of regulatory asset balances or carrying charges accrued on those balances. (Ex. 142 at 2-9; Ex. 41 at 1-6).

438. Additionally, FEA's proposal to retroactively exclude regulatory asset balances and carrying charges, on the basis of excess earnings, from rate recovery violates Commitment 4 of the stipulation approving the MidAmerican acquisition. Commitment 4 states that "normal rate case rules and

procedures" would apply to "costs and revenues, and any under or over earnings would accrue to the Nevada Utilities until the next rate case filings." (Ex. 142 at 39; Docket No. 13-07021 Order issued on December 17, 2013, at 25).

PUCN Discussion and Findings

439. The PUCN grants Nevada Power's request for rate base recognition and a three-year amortization period for expenses Nevada Power incurred in filing and presenting of its 2014 general rate case and 2015 integrated resource plan.

440. FEA recommends that both deferred integrated resource plan and general rate case costs *and* the accumulated carrying charges be excluded from rate recovery. FEA is correct in stating that the PUCN orders in the general rate case Docket No.14-05004 and the integrated resource plan Docket No. 15-07004 did not specifically address regulatory asset treatment for incremental costs incurred in filing and presenting those cases. However, cost recovery for integrated resource plan filing expenses is required under NRS 704.751(3). Nevada Power is correct that cost recovery for the 2014 general rate case is consistent with the reasoning articulated in Docket No. 11-06006.

441. A carrying charge recognizes that Nevada Power will incur financial harm if the time value of money is not recognized for expenses or infrastructure costs prudently incurred between general rate case proceedings. Again, FEA's argument for denying rate base treatment on account of alleged over-earnings is flawed, primarily because it does not account for Commitment 4 established in the MidAmerican acquisition in Docket No. 13-07021.

G. Savings for Nevada Power that May Arise During Next Rate-Effective Period

1. Potential for Debt Refinance

Party Positions

442. Nevada Power seeks to use its test period long-term cost of debt in its calculation of rate of return. (Ex. 23 at 2-3; Ex. 24 at 1-3; *See* Ex. 3 at 48-64).

443. MGM argues that Nevada Power will refinance $1.3 billion of debt in 2018 and 2019, which will occur during the rate-effective period. This relatively high cost of debt will likely be replaced with much lower cost of debt. Accordingly, MGM recommends that the PUCN require Nevada Power to quantify all of the revenue requirements associated with expiring debt, less any costs for the replacement debt. The difference should be used during the rate-effective period to reduce the deferred and ongoing decommissioning costs associated with the Reid Gardner and Navajo plants. (Ex. 118 at 6-7).

444. MGM contends that if there are sums associated with the savings in Nevada Power's financing costs that exceed the decommissioning costs, those funds could be placed in a reserve account and earn

a return based on Nevada Power's authorized ROR. At the next rate case, any funds in the reserve account could be used to reduce Nevada Power's projected expenses and future revenue requirements. If 100 percent of the interest expense reduction from refinancing is placed into the reserve account and excess earnings as now reported quarterly continues to show the pre-refinancing interest expenses, this removes the interest expense savings from the excess earnings mechanism. (*Id.* at 7). As such, MGM states that Nevada ratepayers should receive 100 percent of the interest savings as in the acquisition docket, MidAmerican (now Berkshire Hathaway) assured parties that a benefit of this acquisition would be greater access to lower-cost capital. (*Id.* at 7-8).

445. SNGG states that the cost of Nevada Power's embedded debt is not reasonable based on the following comparisons: (1) Sierra Pacific's long-term debt is 275 basis points lower than Nevada Power's; (2) Regulatory Research Associates Electric Utilities Summary is 239 points lower than Nevada Power; and (3) all other Berkshire Hathaway utilities have lower long-term debt costs. (Ex. 50 at 38-39). SNGG further states that certain debt will be refinanced during the rate-effective period. All of this debt will likely be refinanced at significantly lower rates, saving Nevada Power, but not ratepayers, over the period during which the new rates will be in effect. (*Id.* at 39). Therefore, SEA suggest that the PUCN do one of the following in this case: (1) take no action; (2) adjust Nevada Power's ROE to 7.5 percent; (3) adjust cost of debt to 4.27 percent; (4) adjust the May 2018 Series O debt maturity to 4.27 percent; or (5) order Nevada Power to file a new general rate case in 2018. (*Id.* at 40-43).

446. SNGG agrees that a regulatory liability could be established to record the savings Nevada Power may experience from its debt refinancing. (Tr. at 935).

447. FEA states that the current embedded debt cost will substantially exceed Nevada Power's cost of debt during the rate-effective period. Setting rates that knowingly do not reflect a utility's known and measurable cost of service when rates are in effect does not strike a reasonable balance between Nevada Power's shareholders and ratepayers and is not in the public interest. Nevada Power has three bond series totaling over $1.4 billion that will mature during the rate-effective period. Nevada Power will experience interest rate savings attributable to refinancing these bonds predominantly due to its acquisition by BHE and improvement in Nevada Power's bond rating. To recognize this reduction, the PUCN can either make an estimate of what the debt interest expense will be on average over the next three years, or the PUCN can direct Nevada Power to record in a regulatory liability account the interest rate savings that are certain to be realized when it refinances these mature debt series in 2018 and 2019. (Ex. 117 at 4-6).

448. FEA states that Nevada Power should be required to carry regulatory liabilities at the same carrying charge as regulatory assets. Both regulatory assets and regulatory liabilities should be adjusted by deferred taxes and the after-tax balances should be netted against one another to determine the net of tax regulatory asset/liability that to be carried to Nevada Power's next rate case. (*Id.* at 8).

449. SEA supports the cost of debt recommended by FEA. As an alternative to imputing FEA's proposed cost of debt for the rate period, the PUCN could use Nevada Power's cost of debt and establish a regulatory liability to capture impacts of Nevada Power's re-financing in 2018 and 2019. (Ex. 49 at 5).

450. BCP proposes that Nevada Power be required to calculate interest expense savings that it will realize during the ensuing three-year rate-effective period and accrue such calculated interest expense savings within a regulatory liability account. In Nevada Power's next GRC, in 2020, the parties can determine a period over which such deferred savings can be credited to Nevada Power's retail cost of service. Within the 2018-2019 time frame, Nevada Power has three long-term debt securities that sum to a little over $1.3 billion that will mature. Each of the three debt securities have, by today's standards, well above current-market rates. It is anticipated that when Nevada Power refinances the three maturing debt securities at today's lower market rate, Nevada Power will begin to immediately achieve significant interest expense savings. (Ex. 65 at 58, 61-62).

Rebuttal

451. Nevada Power states that the parties seek to circumvent the historical test period concept by reaching into a future period for an asymmetrical, single-issue adjustment, and their recommendations should be rejected. (Ex. 36 at 12).

PUCN Discussion and Findings

452. As initially addressed in the Cost of Capital portion of this Order, the PUCN reiterates its rejection of the intervening parties' positions with respect to imputing a cost of debt for the purpose of calculating Nevada Power's rate of return. This is because Nevada uses a historical test year adjusted for known and measureable changes at the certification date (within 6 months after the date of filing). It is required by law. *See* NRS 704.110(3). A utility may also file a statement of expected changes in circumstance for items reasonably known and measurable with reasonable accuracy that may occur within 210 days after the application is filed. *See* NRS 704.110(4).

453. Additionally, the revenue requirement calculation is based on historical data or, at the very least, that which is reasonably known and measurable with reasonable accuracy within a statutorily-prescribed time frame. The intervening parties' recommendations clearly reach beyond the statutory time period.

454. The parties have presented information suggesting that Nevada Power will be able to obtain refinancing at significantly lower long-term debt costs, but this data is speculative and relies on prior and current historical rates to project what Nevada Power will be able to obtain in debt financing terms in a 6 to18 month future period. The recommendations do not satisfy the "known and measurable" threshold through which Nevada has consistently set just and reasonable rates.

455. While the PUCN rejects proposals to reach outside the test period to establish cost of debt, the PUCN takes note of recommendations to establish a regulatory liability to capture any potential savings Nevada Power receives from its debt refinancing. The PUCN believes that the goal of the proposed regulatory liability is substantially achieved through the PUCN's decision to establish an earnings sharing mechanism, as discussed below in this Order.

456. Based on this reasoning, the PUCN shall not establish a regulatory liability for any potential savings that Nevada Power may receive from its debt refinancing because any windfall to Nevada Power from refinancing would be captured by the newly-established earnings sharing mechanism. In accordance with the PUCN's discussion and findings in this Order, such savings have the potential to be portioned appropriately between Nevada Power and ratepayers.

2. Pending Tax Cut and Jobs Act

456A. The Tax Cut and Jobs Act (at least the name by which is was formerly known), which was recently passed by the United States Congress as HR 1, purports to cut the federal corporate tax rate from 35 percent to 21 percent. This federal tax cut may significantly benefit corporations, such as Nevada Power, over the next rate cycle and create over earnings.

H. Earnings Sharing Mechanism to Address Future Over-Earning

Party Positions

457. MGM advocates for establishing an excess-earnings mechanism because Nevada Power earned net incomes that greatly exceed those allowed in the rate case setting. To the extent that Nevada Power earns in excess of allowed returns, these excess returns are unfair and unreasonable to ratepayers. A properly-constructed excess-earnings mechanism could bring about a better degree of fairness and reasonableness to present and future ratepayers and to shareholders. (Ex. 118 at 3-4).

458. MGM recommends that Nevada Power be permitted to keep 100 percent of any earnings over its authorized rate of return (ROE) up to the first 50 basis points, but not to exceed 9.5 percent. It will encourage Nevada Power to continue its cost-cutting efforts because it will be rewarded for doing so. Moreover, 50 percent of all excess earnings above the authorized ROE plus 50 basis points should be used to finance and reduce the recorded decommissioning costs related to Reid Gardner and Navajo by placing the 50 percent of excess costs in a regulatory account. (*Id.* at 5).

459. If there are earnings in excess of the amount necessary to pay the decommissioning costs of Reid Gardner and Navajo, MGM proposes that the PUCN create a reserve account into which 50 percent of these excess earnings are placed. These segregated funds would earn a return based on Nevada Power's authorized ROR. In Nevada Power's next general rate case, the funds placed in this reserve account should be used to reduce projected expenses and offset future revenue requirements. (*Id.* at 5-6).

460. BCP witness Dittmer stated that BCP evaluated the pros and cons of an earnings sharing mechanism and declined to give a further opinion. (Tr. at 706).

Rebuttal

461. Nevada Power witness Bethel stated that to his knowledge there was no direct rebuttal to this issue. (Tr. at 1340-41). Bethel states in his Cost of Capital rebuttal testimony that setting revenue requirement sharing policies and regulations on a prospective basis is not a new concept. He added that Nevada Power President and Chief Executive Officer Paul Caudill has even suggested in past proceedings that if parties could agree on a mechanism, Nevada Power would likely support it. One of the key concepts in reaching such an agreement, however, will be consensus on exactly when, and if, Nevada Power is actually earning in excess of the ROE approved by the PUCN. (Ex. 41 at 19).

PUCN Discussion and Findings

462. Whether or not Nevada Power has been overearning is hotly contested in this proceeding. Many, if not all, of the intervening parties have expressed concerns that Nevada Power was earning well in excess of its authorized ROE and, they believe, earning a windfall. Nevada Power strongly disputes any assertion that it was over-earning and challenges any party asserting otherwise to provide any evidence supporting such a claim.

463. The PUCN has legal responsibility to ensure that any charges imposed on Nevada utility customers are "just and reasonable," *see* NRS 704.001(4); NRS 704.120(1), which is a statutorily-imposed standard consistent with the PUCN's responsibility to "[p]rotect, further and serve the public interest." *See* NRS 703.151(1). Yet, the PUCN is also legally required to balance the public interest with the interest of shareholders of a public utility to ensure that the utility has "the opportunity to earn a fair return on their investments . . ." NRS 704.001(4).

464. As previously discussed in this Order, the touchstone of any PUCN proceeding should be achieving fairness and reasonableness in addressing concerns of the public *and the utility*.

465. Sometimes the perception of unfairness is every bit as destructive as actual unfairness. Meaning, a belief can at times be as powerful as reality, irrespective of whether it is true or not. Here, to address any future concerns that Nevada Power may be over-earning beyond its fair share, the PUCN

shall for the first time set in place a mechanism to set an outer limit or otherwise capture for the benefit of Nevada ratepayers a portion of any over-earning that may occur.

466. This mechanism shall be as follows: Nevada Power shall be permitted to keep 100 percent of any earnings it receives in excess of the 9.4 percent ROE that has been established in this Order, until it reaches a 9.7 percent ROE, after which all earnings shall be split 50/50 with Nevada Power's ratepayers. The 9.7 percent ROE is the lower limit identified by Nevada Power as being within a reasonable range. This earnings sharing mechanism eases concerns regarding Nevada Power receiving a windfall for refinancing long-term debt at cheaper rates and incurring savings from future changes to federal tax legislation. The PUCN agrees with MGM that such a mechanism also incents Nevada Power to continue cost-cutting measures. It is fair to Nevada ratepayers and Nevada Power.

467. If any earnings occur beyond 9.7 percent, allocation of customers' share of such earnings shall be adjudicated in Nevada Power's next general rate case to provide flexibility to best allocate any monies and for parties to provide recommendations.

468. The PUCN hereby directs Nevada Power to file with the PUCN, within 150 days of this Order, as a compliance item, an informational filing explaining its plan to implement the earnings sharing mechanism and its proposed methodology for tracking and recording any potential over-earnings to be allocated to ratepayers. Nevada Power shall file its earnings sharing calculation informationally with the PUCN in Nevada Power's annual DEAA filing by March 1, 2019, for calendar year 2018.

I. Adjusting Rate of Return Calculations

Party Positions

469. In response to intervener party positions asserting that Nevada Power is over-earning on its authorized rate of return (ROR), Nevada Power states that it is not over-earning and asserts that MGM basis its assertions of over-earning on a single measure of earnings, the end of year quarterly calculations of regulatory earned rates of return and return on equity that Nevada Power (and Sierra Pacific) file with the PUCN in compliance with Docket No. 13-07021. NV Energy states that these quarterly reports reflect an earned rate of return greater than the rate of return used to set rates in Nevada Power's 2014 general rate case. (Ex. 41 at 2-3).

470. Nevada Power witness Bethel states that these quarterly rate of return reports have a structure and content that are decades old, based on a unique, highly-adjusted and, given the prominence of regulatory assets and liabilities in today's environment, outdated. The quarterly report calculations do not reflect investments and expenditures that have been segregated into regulatory assets or liabilities,

and certain plant investments[20] reflected on the Company's books and records as plant in service. Nevada Power has not been granted authority to recover these investments in current rates, either through rate base or some other mechanism and, therefore, they are not reflected in the quarterly returns reports. By including these investments in rate base and in the calculation of earned return, Nevada Power shows a reduction in operating income. Nevada Power's adjustments also add the net book values of LV Cogen, SunPeak, and Nellis Solar, in addition to the decommissioning costs of Reid Gardner. (*Id.* at 4-6).

471. Nevada Power states that the current quarterly rate of return report ignores expenses deferred from the calculation of operating income as well as the rate base associated with plant balances and also adjusts out the regulatory asset associated with deferrals. Nevada Power notes that it is important to at least be able to note on the earned rate of return report that if Nevada Power were to make adjustments for expenses incurred and capital costs that have been included and reported in accordance with FERC accounting treatment as plant in service, a modified rate of return would be lower than is reflected in the current accounting process. NV Energy opines that correcting the quarterly returns report to include such adjustments would go a long way to ensuring a more true and accurate measure of Nevada Power's regulatory earnings. (*Id.* at 8-10).

472. BCP disagrees that the unbalanced and asymmetrical treatments afforded regulatory assets and regulatory liabilities have contributed to Nevada Power's regulatory earning in excess of its authorized return. Absent the identification of significant new investment requirements or increases in expenses being recovered in base rates, it is anticipated that the refinancing of high-cost debt will result in additional over-earnings. (Ex. 65 at 19-22; 62).

473. Staff recommends denying Nevada Power's modification to the earned rate of return calculations. Staff does not support adjustments to the calculation related to the regulatory assets that the PUCN has approved as a result of the ERCR plan.

Rebuttal

474. Nevada Power argues that a decline in rate base is the primary driver of the increase in return as reflected in the quarterly earnings reports provided by Nevada Power. With the early retirement of Reid Gardner Units 1-3 and the transfer of the undepreciated book value out of rate base and into a regulatory asset, net plant in service has declined in 2015 and 2016. Depreciation expense has

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[20] Examples of such investments before the PUCN in this general rate proceeding include: plant in service amounts related to the acquisition of SunPeak, LV Cogen, and the Nellis Solar facility, pursuant to the ERCR plan; the Reid Gardner decommissioning cost regulatory asset; the regulatory asset encompassing operation costs of LV Cogen, SunPeak, Nellis, and Silverhawk have been deferred; and the regulatory asset encompassing a lease expense for the ON Line transmission line. (Ex. 41 at 4).

exceeded the plant placed in service. The earnings reflected in the quarterly reports do not reflect assets funded but not in rate base. (Ex. 142 at 3-4). Nevada Power states that it believes the parties can get together and come up with a (reporting) solution. Nevada Power is looking for a reporting mechanism that is much more accurate and transparent than the one in place today. (Ex. 142 at 10).

PUCN Discussion and Findings

475. The PUCN declines at this time to modify Nevada Power's earned rate of return calculations. However, the PUCN acknowledges that the calculation of the regulatory earned rate of return (ROR) and returns on equity (ROE) should be revisited to obtain a potentially more accurate representation of any over-earnings or under-earnings experienced by Nevada Power. The PUCN directs Nevada Power, Staff, and BCP to informally work toward arriving at a consensus on any appropriate modifications to be reflected in filings, beginning with the filing to be made on May 1, 2018, for the rolling 12-month period ending March 31, 2018.

476. If the parties cannot reach a consensus on an informal basis, Nevada Power shall report such to the PUCN, and the PUCN may consider opening an investigatory docket as it deems necessary. Moreover, the PUCN hereby directs Nevada Power to continue to file indefinitely with the PUCN the monthly financial statements, quarterly calculations of Nevada Power's regulatory rates of return and return on equity, and monthly deferred energy accounting reports as currently filed in compliance with Commitment 24 of the Stipulation entered into in Docket No. 13-07021. Nevada Power should continue to make those filings in Docket No. 13-07021.

VIII. RATE DESIGN

477. The Rate Design phase is the "rate structure, or mechanism whereby a utility realizes its revenue requirements." *Washington Gas Light Co. v. Public Service Commision*, 450 A.2d 1187, 1195 (D.C. 1982). Here, the Rate Design hearings were held on December 4-5, 2017, and December 7-8, 2017. Twenty-one (21) witnesses testified. Fifty-one (51) exhibits were admitted into evidence. Below are the issues, the positions of the parties, and discussion and findings.

A. Overarching Rate Design Issues

Party Positions

478. Nevada Power's proposed rates are presented in Statement O. Nevada Power provided 4 versions of Statement O reflecting 4 different revenue requirements in its initial and certification filings. These are (1) Statement O ECIC: Statement O after ECIC with no calculated increase to revenue requirement; (2) Statement O CERT: Statement O at Certification with no calculated increase to revenue requirement; (3) Statement O ECIC Per NRS: Statement O after ECIC with a calculated increase in revenue requirement pursuant to NRS Chapter 704 and NAC Chapter 703; and (4)

Statement O CERT Per NRS: Statement O at Certification with a calculated increase in revenue requirement pursuant to NRS Chapter 704 and NAC Chapter 703. In both initial and certification testimony, Nevada Power's preferred proposal is Statement O ECIC at present revenue requirement. (Ex. 171 at 2, 6-8; Ex. 172 at 3-5; Ex. 4 at Statement O ECIC, Statement O CERT, Statement O ECIC Per NRS, Statement O CERT Per NRS; Ex. 157 at Statement O ECIC, Statement O CERT, Statement O ECIC Per NRS, Statement O CERT Per NRS).

479. Staff recommends approving the rate design methodology proposed by Nevada Power in its original filing, whereby Nevada Power proposed to maintain the basic service charge and demand, *i.e.*, volumetric, charges for all customer classes not affected by Assembly Bill (AB) 405, with a slight modification to Nevada Power's proposed allocation of Senate Bill (SB) 123 credits to all customer classes. If any change in revenue requirement is approved by the PUCN, the BTGR should be allowed to vary accordingly. (Ex. 192 at 2). Staff recommends that the PUCN deny the rate design for AB 405 combined customer classes proposed in Nevada Power's Certification filing and instead approved Staff's alternative methodology. AB 405 does not mandate how rates should be developed. Nevada Power could have—and should have—developed rates consistent with its rate design in the original filing that would maintain the basic service charge and allow the BTGR to vary. (Ex. 192 at 7-8).

480. Staff also recommends that the PUCN order Nevada Power to retain all NEM schedules at the current rates until all existing customers have opted into their otherwise-applicable rate schedule (pursuant to Section 28.3(5) of AB 405), or until the PUCN orders the NEM schedules to be closed. (Ex. 190 at 10-11).

Rebuttal

481. Nevada Power recommends that the PUCN approve Nevada Power's rebuttal rate design proposal, which is supported by Staff, SNGG, and Walmart, and maintains the current basic service charges and demand charges for all classes. (Ex. 203 at 6). Nevada Power disagrees with Staff's suggestion that the PUCN order Nevada Power to retain all NEM schedules at the current rates until such time as all existing NEM customers have opted into their otherwise-applicable rate. In the Order in Docket No. 17-07026, the PUCN directed Nevada Power to charge all NEM customers—including pre-June 15, 2017, NEM customers—the same rates as similarly-situated customers without NEM systems. (Ex. 201 at 4-5).

PUCN Discussion and Findings

482. The PUCN directs Nevada Power to use the Statement O contained in its rebuttal case, Exhibit 203, as the basis to implement the adjustments ordered herein. For the first time in known history, the monthly fixed basic service charge shall be reduced for several customer classes. Single family

residential (RS) fixed charges shall be reduced from $12.75 to $12.50 per month. The monthly basic service charge for the following other customer classes shall also be reduced by $0.25, including the multi-family residential (RM), large single family residential (LRS), and small commercial (GS) classes. Nevada Power is directed to make any other adjustments to rates necessary to implementing the modifications in this Order *via* adjustments to volumetric BTGR rates.

483. The PUCN directs Nevada Power to make any adjustments to rats as necessary to implement the modifications in this Order. These reductions are hereby ordered by the PUCN to shall take effect and be implemented by Nevada Power as soon as reasonably possible.

B. Monthly Basic Service Charge Reductions

1. Residential Single Family Basic Service Charge Reduced

Party Positions

484. Nevada Power provides 4 certification statements with corresponding changes in revenue requirement. Nevada Power's preferred proposal is to maintain rates at current levels so that total proposed rate revenue remains equal to the revenue resulting from current rates. Current rates recognize the expected change in circumstances due to the exit of two customers from bundled service. (Ex. 172 at Pollard Cert-3, at 3-4).

485. Nevada Power had stated that the newly-combined rate class for NEM and non-NEM customers is effectuated in this general rate case filing. (Ex. 172 at Pollard Cert-3, at 3-4). Nevada Power initially recommended raising the basic service charges on single family residential customers from $12.75 to $17.36 per month. (Ex.157 at A-2). However, as discussed below in rebuttal, it withdrew this proposal.

486. Sunrun contends that Nevada Power's proposal to raise the basic service charge from $12.75 to $17.36 should be summarily rejected. Sunrun states that there is no requirement for the basic service charge to increase and that it remains unclear why Nevada Power proposed the increase at all. Increasing the basic service charge will result in lower volumetric charges. Yet, higher volumetric charges can result in more energy efficiency. Sunrun maintains that the proposed increase in the basic service charge is counterproductive to rooftop solar because lower volumetric charges may increase use and therefore be at odds with the goals of energy efficiency. (Ex. 185 at 11-16, 18, 23-24).

487. Vivint Solar states that it is critical that the basic service charge be relatively small, reasonable, and fairly distributed across all residential ratepayers. Nevada Power could increase its volumetric rate to ensure reasonable cost recovery. Alternatively, Nevada Power could propose a small minimum bill provision. Vivint Solar contends that increasing the basic service charge and decreasing volumetric rates harms NEM, fixed-income, and low-use energy customers. Keeping the basic service charge 'as

is' and increasing the volumetric rate is consistent with the intent of AB 405 and the stated objectives of the PUCN's NEM Order in Docket No. 17-07026. (Ex. 187 at 5-9).

488. Vote Solar states that the PUCN should encourage distributed generation and energy efficiency and provide more control of bills to customers, especially low-income customers, by keeping the basic service charge at its current level, or decreasing it. AB 405 does not require revisions to the basic service charge. Moreover, Vote Solar contends that a high basic service charge causes the value of residential solar to decline and disproportionately harms low-income customers. (Ex. 179 at 3, 27-32; Tr. At 1780-81).

489. SEA states that Nevada Power's proposal to drastically increase the basic service charge for the newly-combined residential rate classes could be viewed as an attempt to harm the solar industry. The State of Nevada clearly values these clean resources, as evidenced through its legislative action, and Nevada Power should not be permitted to perpetuate its anticompetitive behavior. Nevada Power did not retain the existing basic service charge rate and develop whatever new energy rate was needed to collect the amount of dollars necessary from the residential class of customers. An increase to the basic service charge has a negative impact on NEM customers that, over a 20-year life, without interest, amounts to nearly $600. (Ex. 196 at 2, 13-14).

490. BCP recommends denying the Nevada Power's proposed increase in the basic service charge. High fixed costs reduce customer control and have the biggest impact on small customers. According to BCP, the lowest 5 percent of energy users would see an increase in general rates of 21 percent, while the highest 5 percent of energy users would see a decrease of 14 percent. Rule 9 costs should not be recovered through a higher BSC but rather through the Rule 9 allowance. Rule 9 facilities costs are not marginal costs, but rather sunk costs recovered through the Rule 9 allowance and developer contribution if necessary. Rule 9 costs reflect the costs to connect to the grid. BCP argues that the basic service charge should only include direct customer costs. (Ex. 188 at 2-9).

491. Staff states that the PUCN should deny Nevada Power's proposed increase. Stability of rates is a fundamental tenet of rate design. Staff is concerned that customers will have a difficult time accepting the significant increase in the basic service charge from that proposed in Nevada Power's original filing. (Ex. 192 at 7-13).

Rebuttal

492. Nevada Power rescinds its previously-proposed increase to the basic service charge and proposes maintaining the basic service charge at its current rate of $12.75 per month. (Ex. 203 at 6).

PUCN Discussion and Findings

493. The PUCN hereby finds and concludes that a reduction in the fixed monthly basic service charge to all single family residential customers of Nevada Power is appropriate under the facts of this case. Accordingly, for single family residential customers, the monthly basic service charge shall be reduced from its current rate of $12.75 to a new rate of $12.50 per month. This reduction is historic and unprecedented in Nevada. Since 1979, the basic service charge has periodically increased.

494. Earlier in this Order, the PUCN addressed Nevada Power's cost of capital, depreciation, and revenue requirement. In these sections, the PUCN made findings of reasonableness and prudency, including findings that decreased the revenue requirement. The portion of the decrease that is allocable to the residential rate class will be used to decrease the basic service charge, as well as the volumetric BTGR that will be discussed in a later section of this Order.

495. The basic service charge is an important mechanism for a utility to recover fixed costs. Rate design should balance the need for recovery of these fixed costs with the principles of sending proper price signals and creating stability in rates. Decreasing the basic service charge in this case to $12.50 for single family residential customers achieves this balance between the public interests and Nevada Power stability. This reduction also sends a price signal that encourages residential ratepayers to conserve energy and promotes stability by allowing customers to exercise greater control over their total bills.

496. Lowering basic services charges assists Nevada residents on a fixed income and is consistent with the policy of the State of Nevada to accelerate the growth of rooftop solar pursuant to AB 405. Higher volumetric charges encourage energy efficiency and investment in distributed resources, both of which were identified as priorities by the Nevada Legislature and signed into law by Governor Brian Sandoval through the passage of Assembly Bill 223, Assembly Bill 405, Senate Bill 145, Senate Bill 146, Senate Bill 150, and Senate Bill 204. Legislative policy, tenets of rate design, and the record in this proceeding support the PUCN's finding that it is reasonable, equitable, and prudent to reduce the basic service charge from $12.75 to $12.50.

2. Basic Service Charges Reduced for Other Customer Classes

497. The PUCN finds that it is reasonable and prudent to reduce the basic service charge by $0.25 for the following other rate classes of Nevada Power for the reasons discussed above: multi-family residential (RM), large single family residential (LRS), and small commercial (GS) classes.

C. Volumetric Charge Reductions

498. In addition to a reduction in the basic service charge discussed above, the PUCN also finds that it is reasonable and proper to reduce the usage, *i.e.*, volumetric, charges for Nevada Power customer

classes too. A reduction in the volumetric charge achieves a balance with the reduction in the basic service charge, and allows a reduction in monthly rates of *all* customers, including large commercial customers too.

499. The volumetric use charges for *all* customer classes shall be reduced by approximately $27 million.[21] The exact amount of this reduction shall be calculated by Nevada Power in its tariffs and transmitted to the PUCN for review. However, preliminary projections by the PUCN based upon data in the record show that the reduction may be up to 2 percent reduction to a single family residential customer's monthly bill.

C. NET ENERGY METERING (NEM) ISSUES

1. Time-of-Use (TOU) Rates

Party Positions

500. Nevada Power contends that implementation of Section 24 of AB 405 requires the deletion or modification of all existing tariffs governing separate NEM classes, including the NEM riders NMR-A, NMR-B and NMR. As a part of the tariff clean-up process, Nevada Power proposes modifications to the current, optional time-of-use (TOU) tariffs. Nevada Power suggests that the optional TOU tariffs should be closed to new customers; but the existing optional TOU tariffs should remain in place so that existing customers are able to migrate to the new TOU tariffs effective April 1, 2018. (Ex. 163 at 4-6). Nevada Power proposes a four-part TOU rate that includes a basic service charge, a monthly demand charge, a TOU on-peak demand charge, and TOU varying energy rates. (Ex. 172 at 23).

501. Sunrun asserts that AB 405 does not require Nevada Power to cancel its current optional two-part TOU tariffs. Sunrun requests that the existing two-part rates should be maintained to continue to provide benefits to Nevada Power's customers, including the 7,300 customers on existing TOU rates. Sunrun states that Nevada Power's proposed four-part tariff is outside the scope of this proceeding. (Ex. 185 at 5-7, 11). While Nevada Power recognizes the benefits from TOU rates, Sunrun contends that Nevada Power made substantial changes to these existing rates in its September 5, 2017, filing. The existing two-part rate incents energy conservation more than the proposed four-part rate because the proposed four-part rate collects relatively more revenue through fixed charges. Sunrun supports a rate design that collects more revenue through higher volumetric charges, which promotes a reduction in overall and peak energy use. (Ex. 185 at 6-9).

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[21] This estimated reduction is based on present rate revenues.

502. Vote Solar states that the PUCN should reject Nevada Power's proposal to close existing TOU rate schedules. Vote Solar states that there is no conflict between implementing AB 405 and offering different choices for TOU rate options, including the current optional TOU rates. (Ex. 179 at 32-33).

503. Staff recommends denying Nevada Power's request to cancel the existing optional TOU rates for residential and small general service classes. Staff recommends retaining these rates based on the class specific billing determinants from Nevada Power's certification filing. Furthermore, AB 405 does not require the elimination of the current optional TOU rates. (Ex. 190 at 2-5). However, Staff agrees with Nevada Power's assertion that moving summer weekends to the off-peak period for all existing optional TOU rates may improve customer acceptance. Staff recommends approving Nevada Power's request to move summer weekends to off-peak for the existing TOU tariffs. (Ex. 190 at 7-8).

Rebuttal

504. Nevada Power argues that the PUCN should retain the existing TOU rates for existing customers only until an AB 405 TOU rates decision is made or, in the alternative, accept Nevada Power's optional existing and new rates redesigned to better-reflect costs. Nevada Power proposes to defer a resolution of any TOU rate issues into the PUCN's AB 405 docket, where the PUCN will examine TOU rates in early 2018. (Ex. 206 at 3, 31, 48).

PUCN Discussion and Findings

505. The PUCN retains the existing TOU rate classes and structure and denies Nevada Power's request at this time.

506. Section 27.4(c) of AB 405 expressly provides that a decision on new TOU rates shall be made by the PUCN by March 15, 2018. The inclusion of this specific date evinces a legislative intent to have new TOU rates adjudicated in a separate proceeding outside of a general rate case. The PUCN issued an Order in Docket No. 17-07026 on November 29, 2017, scheduling a pre-hearing conference for February 8, 2018, to address new TOU rates as mandated by AB 405. On December 11, 2017, the PUCN issued another Order in Docket No. 17-07026 permitting pre-hearing briefing to occur on or before January 25, 2018. A key focus of creating new TOU rates for Nevada is to encourage the development and use of battery storage. Closing, cancelling, or otherwise substantially modifying the available TOU rate offerings before the PUCN's decision in Docket No. 17-07026 would result in unnecessarily modifying TOU rates twice in a three-month period and would be premature. No change to the current TOU rate structure shall occur in this case.

2. Removing AB 405 Designation from Customer Names

507. Some of Nevada Power's proposed certification tariffs include a new "405" suffix for certain rate classes affected by AB 405. (Ex. 157 at Exhibits A-1, A-1 TOU, A-2, A-2 TOU). Yet, a tenent

of AB 405 is to eliminate any discrimination or disparate treatment of NEM customers from non-NEM customers. Designation of a specific "405" reference to NEM customer classes is unnecessary and gives the appearance of a 'Scarlet Letter' type label, which is contrary to Nevada law. This initial designation by Nevada Power may have been inadvertent with the rapid new changes. Nevertheless, Nevada Power filed tariffs with the PUCN in September 2017 that do not include reference to "405." The PUCN commends Nevada Power for doing so, and no further action is required. It appears moot.

3. Regulatory Asset Treatment for Alleged AB 405 Costs

Party Positions

508. Nevada Power requests that the PUCN extend the revenue shortfall regulatory asset mechanism approved in its September 1, 2017, Order in Docket No. 17-07026 (AB 405 Order) until Nevada Power's next general rate case in 2020. This extension would permit Nevada Power to return to its original rate design proposal. (Ex. 206 at 3).

509. BCP opposes any extension of the AB 405 regulatory asset. BCP categorizes Nevada Power's request as a form of 'single-issue ratemaking.' BCP argues that revenues may increase and that regulatory assets should be used to track actual costs, not lost revenues. (Tr. at 1852-1853).

510. Staff recommends that the PUCN reject Nevada Power's proposal to extend the regulatory asset treatment for AB 405 costs. According to Staff, the regulatory asset in question is supposed to be closed at the end of the proceedings in the instant case because Nevada Power's revenue requirement will have been established and will be fully recovered by rates approved by the PUCN as just and reasonable. With new rates in effect, Nevada Power has every opportunity to recover costs and achieve the authorized return. There is no revenue requirement deficiency or under-collection to justify the regulatory asset extension request. Staff adds that Nevada Power appears to suggest that there will be under-collection from NEM customers; such under-collection, if any, is recovered from other customers through interclass balancing, and therefore, there is no revenue shortfall. Nevada Power's suggestion is a form of single-issue ratemaking. If the PUCN chooses to approve this request, it would also have to establish cost-based rates for NEM customers to track the costs. (Tr. at 1998-2002).

PUCN Discussion and Findings

511. The PUCN set forth in its September 1, 2017, Order in Docket No. 17-07026 that it was establishing a regulatory asset for Nevada Power regarding the implementation of AB 405 to guard against a "potential liability." The PUCN's creation of that asset is not an implicit endorsement of the position that a liability actually exists; but it is protection for the utility in the event that one does.

512. Landmark changes to the laws and policies of Nevada regarding NEM and rooftop solar have occurred in a relatively short amount of time throughout the latter part of 2016 and 2017. The inertia

of those changes may create uncertainty about the future in the views of some holding onto the past; whereas they create hope for others. Recognition of that uncertainty is found in Section 28.5 of AB 405 where the Nevada State Legislature directed the PUCN to open an investigatory docket to determine what, if any, financial impact NEM may have on Nevada customer rates. The premise of this study acknowledges there are impacts that remains unknown about NEM. As the PUCN recognized in consolidated Docket Nos. 16-06006 through 16-06009, further study is necessary and important for Nevada to lead on this issue.

513. Given this study is ongoing, the PUCN finds that it is fair and reasonable to approve Nevada Power's request to extend the regulatory asset treatment for AB 405 that was previously approved by the PUCN in Docket No. 17-07026. Recovery is not guaranteed to Nevada Power, as any regulatory asset will be vetted by the PUCN, Staff, BCP, and intervening parties at the next general rate case in 2020. Accordingly, the PUCN finds that no substantive modifications are necessary to the PUCN's September 1, 2017, Order in Docket No. 17-07026 establishing this asset for Nevada Power, and the directives to Nevada Power in that Order shall remain in place.

514. Additionally, the PUCN has formally opened an investigatory docket as Docket No. 17-07013 in response to the directives of Section 28.5 of AB 405. That docket may be the most appropriate forum for further discussion and deliberation about any NEM costs. The more information, the better. The PUCN directs Nevada Power to track any alleged general rate revenue "deficiency" it believes results from AB 405 and include a discussion of this alleged deficiency in comments filed in Docket No. 17-07013. This tracking should gather data on any difference between general rate revenues (basic service charge plus BTGR) and cost-based rates used to establish the NMR-A rate rider using the revenue requirement revised for the adjustments in this Order. This information should be filed as a compliance item. Nevada Power is also directed to continue to comply with directives "n" and "o" in the PUCN's September 1, 2017, Order in Docket No. 17-07026.

4. Advanced Notice of Excess Energy Credit for NEM Customers

Party Positions

515. Nevada Power's proposed tariffs include a calculation of the excess energy credit to be paid to NEM customers. (Exs. 2 and 157 at Exhibits A-1, A-1 TOU, A-2, and A-2 TOU).

516. Sunrun states that Nevada Power's statement of rates should be transparent on future excess energy credits and that Nevada Power should correctly calculate excess energy credits for its two-part TOU rates. AB 405's language is specific regarding how excess energy should be credited. Here, Nevada Power correctly calculates excess energy credit amounts for its non-TOU rates, but the two-

part TOU rates are not correct. Nevada Power does not provide excess energy calculations for other than the first AB 405 tranche (the 95-percent tranche). It is unknown how quickly this tranche will be subscribed. Transparency in the value of excess energy is critical. Nevada Power should perform the calculation for any current or filled tranche, as well as the next tranche to be filled, and provide it to customers in the statement of rates. (Ex. 185 at 24-25).

517. Staff recommends that Sunrun's recommendation be accepted and Nevada Power be directed to correctly calculate excess energy credits for its two-part TOU rates for both Option A and Option B schedules. (Ex. 191 at 2-3).

Rebuttal

518. Nevada Power agrees with Sunrun and Staff that the excess energy credits for the two-part TOU rates in the current filing are incorrect. Nevada Power correctly filed the excess energy credits in its compliance filing in Docket No. 17-07026, and the excess energy rate will need to be adjusted to reflect the rates ordered in these dockets.

519. Nevada Power disagrees with Sunrun's recommendation to provide excess energy calculations for the unopened tranches. Those calculations will change as the quarterly deferred energy rate changes. If Nevada Power were to publish rates for future tranches, the rates would be incorrect as soon as they are published. Nevada Power prefers to publish rates near the time the next tranche is approached to ensure greater accuracy. (Tr. at 2073-2074).

PUCN Discussion and Findings

520. The PUCN directs Nevada Power to provide correct rates in the new tariffs filed in this case, and as requested by Sunrun and Staff as a result of this proceeding. These rates shall be verified by Staff before acceptance.

521. There is significant information on the PUCN's website at www.puc.nv.gov through NV Energy's Renewable Generations Program with respect to NEM and the MW tranches legislatively-established for the purposes of calculating the excess energy credit to be paid to NEM customers.

522. The initial 95-percent 80MW tranche shows 16.096 MW of applied-for NEM capacity and 5.075 MW of installed NEM capacity as of December 20, 2017. Meaning, there is still considerable room for growth in the first tranche. However, solar installers are in the best position to give advice on what is most beneficial for their customers and/or potential customers. If this information will assist NEM rooftop solar growth in Nevada, then it likely can with little inconvenience.

523. In response to Sunrun and Staff's arguments, the PUCN directs NV Energy to file both Nevada Power's and Sierra Pacific Power's tariffs and include the calculation of the excess energy credit for the next available tranche at the time the currently-open tranche reaches 64MW in applied-for capacity.

This represents 80 percent of the individual 80MW tranches. At that point in time, it will be both practical and beneficial to consumers for NV Energy to file calculations of the excess energy credit rates for the next tranche. Awaiting for a tranche to reach 64 MW is a balanced approach.

5. Investigatory Docket to Study NEM Impacts in Nevada

524. As discussed above, the PUCN has opened an investigation in Docket No. 17-07013 to both determine a methodology for determining what, if any, effect NEM has on non-NEM customers' rates and (once a methodology is determined) to issue a report to the Nevada State Legislature by June 30, 2020. Section 28.5 of AB 405. Stakeholder participation and input in this process, from both NV Energy and *all* rooftop solar companies and advocates, is critical for the PUCN to produce a balanced and meaningful report.

525. Two issues are raised in this case regarding the cost of service for NEM customers: 1) whether the use of "total load" or "delivered load" is appropriate to best determine costs (especially regarding NEM customers) and 2) whether the currently-used Marginal Cost of Service Study (MCSS) improperly separates NEM and non-NEM customers for informational tracking purposes. However, as explained below, the PUCN finds that both issues properly belong in Docket No. 17-07013 and shall be addressed in that proceeding.

a. Use of Total Load v. Delivered Load

Party Positions

526. Nevada Power states that the appropriate starting point for the development of costs imposed by NEM customers is total load (i.e., total household/premise usage absent generation) and total load shape. Most NEM customers were previously full-requirements customers who chose to retrofit their homes with generation behind the meter. Primary and secondary distribution facilities servicing these customers were designed and constructed by Nevada Power before the customer chose to install private generation. Nevada Power continues to use the same facilities to stand by to instantaneously meet the NEM customers' total load, day or night. For all partial-requirements customers, including NEM customers, the costs of those obligations are developed and reflected in the distribution demand cost. (Ex. 171 at 40-42).

527. Vote Solar contends that Nevada Power's cost allocation is improper because Nevada Power does not provide a unique 'standby' service to NEM customers to warrant adding costs in the MCSS. The load shapes that Nevada Power created for NEM customers have no basis in the actual cost of serving those customers. Nevada Power's use of total load, as opposed to delivered load, is comparable to using a theoretical load as opposed to the loads actually served by Nevada Power. There is no

evidence to support the idea that NEM customers are "standby" customers because grid use continues, albeit at somewhat lower levels. Customers using the system less should pay less. (Ex. 179 at 11-16).

528. Vote Solar adds that Nevada Power's improper load shapes lead to an over-allocation of costs to NEM customers. For all other customer classes, Nevada Power uses the delivered load shape for the assignment of costs without adjustment. For NEM customers, Nevada Power uses different load shapes that vary by function: delivered load for generation and energy costs; adjusted total load for transmission costs; and total load plus any net exports for distribution costs. Nevada Power claims to recognize that customers do offset a portion of their demand on the transmission system from the installation of NEM systems; however, Vote Solar maintains that the adjustment Nevada Power applies is flawed and falls short of recognizing the amount of demand that NEM customers reduce at the cost-causing peak periods. Instead, Vote Solar argues that Nevada Power should use delivered load because it represents the extent of transmission load reduction and the timing of those reductions relative to the cost-causing peaks. Nevada Power's current methodology over-allocates in excess of $3 million of transmission and distribution costs to NEM customers. (Ex. 179 at 16-19, 25).

529. Vote Solar urges the PUCN to address the question of load shapes so that rates for NEM customers (and the larger classes to which they belong) resulting from this proceeding are properly determined and do not subsidize the rates of other customer classes. (Ex. 180 at 2).

530. SEA states that its review of the MCSS reveals that NEM customers may not be getting full credit for facility investment savings that are available given that loads are reduced by solar facilities. Nevada Power should not be designing rates under the assumption that it must stand by to serve NEM customer loads as if no solar power production will occur. There is only a very remote chance that all NEM customers served by a substation would suddenly have the rooftop solar output reduced to zero such that the utility is required to have facilities in place to meet such loads. (Ex. 196 at 16-17).

531. BCP recommends that the PUCN direct Nevada Power to use only delivered load for NEM customers in the MCSS. This would be consistent with using only the delivered energy minus the received energy in the four-coincident peak calculation in an embedded cost of service study. Both Staff and Vote Solar demonstrate that Nevada Power is using incorrect load shapes in its MCSS. (Ex. 189 at 14, 16).

532. Staff recommends accepting Nevada Power's MCSS, but also states that it believes that Nevada Power's NEM load shapes for transmission and distribution are overstated. (Ex. 199 at 22).

Rebuttal

533. Nevada Power argues that 'partial-requirements' NEM customer loads vary in multiple ways and that their fundamental relationship with Nevada Power is distinct from Nevada Power's

relationship with non-NEM customers. Interval class load data supports the standby relationship, and is demonstrated by the load data admitted into evidence in Table Wells Rebuttal 2 and 3, as well as Figures Wells Rebuttal 2 and 3. Nevada Power instantaneously responds to any change in both a NEM customer's self-generation and load by delivering more or less energy and concurrently accepting more or less energy. (Ex. at 18).

534. Nevada Power recommends that the PUCN reject the recommendation from Staff and Vote Solar that delivered load should be used to develop the marginal cost of service for NEM customers. Rather, Nevada Power recommends that the PUCN should continue with the approved methodology, which reflects the unique characteristics of those residential and small general service customers who have chosen to install self-generation.

535. Nevada Power states that previously-approved load shapes methodology continues to appropriately allocate the costs incurred by Nevada Power to serve NEM customers, while also reflecting their self-generation. The correct starting point for the allocation is the total load of customers before self-generation because that is the closest measure to maximum demand. Using the delivered load shape instead of the total load shape results in an under-allocation of costs to NEM customers and thereby shifts costs to others.

536. Nevada Power maintains that the enactment of AB 405 does not change the allocation of costs consistent with cost-causation. Additionally, Staff, Vote Solar, and BCP offer no new analysis or evidence regarding load shapes. (Ex. 203 at 6, 28-29, 31, 32, 42).

PUCN Discussion and Findings

537. The PUCN finds that the appropriate venue for discussion of or modification to the practice of using total load versus delivered load is the PUCN's investigation in Docket No. 17-07013.

b. Marginal Cost of Service for NEM Customers

Party Positions

538. Nevada Power included marginal cost of service for NEM customers in the overall MCSS. (Ex. 169 at H-CERT; Ex. 170 at H-CERT).

539. Vote Solar states that the cost of service study should include NEM and non-NEM customers as part of the same rate class, as required by AB 405. AB 405 prohibits treating NEM customers differently than non-NEM customers for any purpose. Nevada Power segregated NEM and non-NEM customers for the purposes of assigning costs in the MCSS. Nevada Power does not treat NEM and non-NEM ratepayers as a single rate class until after Nevada Power reconciles the MCSS results with the embedded revenue requirements. Nevada Power states that it segregated its NEM and non-NEM

customers this way because of the PUCN's open docket addressing AB 405, Docket No. 17-07026, which is outside the scope of this proceeding. (Ex. 179 at 7-9).

540. BCP recommends directing Nevada Power to combine NEM customers with non-NEM customers in Nevada Power's next GRC MCSS. AB 405 prohibits the assignment of a NEM customer to a rate class other than the rate class to which that the customer would belong but for the NEM system for any purpose. Furthermore, medium and large commercial customers with NEM systems are not segregated in the MCSS. (Ex. 189 at 12-13).

541. Staff does not agree that Nevada Power's MCSS should include NEM and non-NEM customers as part of the same rate class. Given that Section 28.5 of AB 405 directs the PUCN to establish a methodology to determine the impact, if any, of NEM customers on rates charged by other customers, Staff states it is appropriate and necessary to distinguish NEM customers from non-NEM customers in a cost-of-service study. The very point of whether the cost to serve NEM customers and non-NEM customers is different is likely to be the subject of the investigation pursuant to Section 28.5 of AB 405, and there is no reason to make a predetermination in this proceeding. (Ex. 200 at 8).

Rebuttal

542. Nevada Power states that AB 405 does not prohibit it from studying the marginal costs of service for NEM and non-NEM customers. Differentiation of NEM and non-NEM customers within the combined residential and small general service customer classes is necessary to track any cost-of-service difference between these customers. Nevada Power also states that by differentiating the costs to serve NEM and non-NEM customers, Nevada Power is gathering information necessary to implement other sections of AB 405. (Ex. 206 at 24-26).

PUCN Discussion and Findings

543. The PUCN finds that Nevada Power's filing complies with AB 405 because NEM and non-NEM customers are charged the same rates, in the same rate class. There is no differentiation in rates charged to NEM and non-NEM customers. Separation of NEM and non-NEM customers for the purposes of the MCSS is appropriate and will serve to inform the PUCN in the upcoming investigation in Docket No. 17-07013. Given the language of AB 405 requiring the PUCN to conduct a study into any potential impact of NEM on the rates of non-NEM customers, it seems the Legislature expressly directed the PUCN to study the cost-of-service breakdown between NEM and non-NEM customers. Gathering information is not prohibited and should be useful to resolving these pending issues.

544. Significant concerns about the adequacy of the MCSS (especially regarding NEM and the unquantifiable (but real) benefits of solar) remain unresolved. The concerns recognized by the PUCN's Order in consolidated Docket Nos. 16-06006 through 16-06009 still ring true.

C. MARGINAL COST OF SERVICE

1. Approval of the Marginal Cost of Service Study

Party Positions

545. Nevada Power requests that the PUCN accept the Marginal Cost of Service Study (MCSS) analysis that it prepared and filed in accordance with NAC 704.655 through NAC 704.66, which it included with its direct and certification testimony. (Ex. 169 and 170).

546. FEA states that MCSS methodologies are 'generally in line' with industry standards and reasonable, with one exception. However, FEA also states that Nevada Power's MCSS is flawed because it overstates marginal Renewable Portfolio Standard (RPS) compliance costs. (Ex. 183 at 2, 4). FEA recommends that the Basic Tariff Energy Rate (BTER) be adjusted to reflect the reality of energy losses on the system between all delivery service voltage levels of customers. Nevada Power's quarterly-adjusted BTER, which collects for fuel and purchased power expense, is not appropriately billed to high-voltage delivery customers. Nevada Power experiences lower energy losses when delivering energy to a high-voltage delivery customer compared to a lower-voltage delivery customer. The BTER should be recalculated to reflect the appropriate loss factor, so as to accurately charge customers to cover Nevada Power's fuel and purchased power costs. (Ex. 182 at 3, 18-23).

547. BCP encourages the PUCN to accept Staff's criticism of the revenue requirement process in Nevada Power's MCSS as valid and acknowledge that the errors overstate Nevada Power's MCSS residential subsidy by $27 million to $28 million per year. (Ex. 189 at 2, 8-9).

548. With respect to generation and energy revenue reconciliation in the MCSS, BCP recommends that the PUCN direct Nevada Power to separately reconcile generation and energy in their MCSS in Nevada Power's next general rate case and exclude energy costs in an embedded cost of service study. Nevada Power has separated the generation and energy functions in the revenue reconciliation process before—in its 2001 general rate case—but changes its methodology in the 2003 general rate case. Additionally, the PUCN's 2011 marginal cost of service investigation in Docket No. 11-12025 resulted in the PUCN accepting NV Energy's recommendation to combine the generation and energy functions in the revenue reconciliation process. However, Docket No. 11-12025 relied upon the "Peaker Deferral Method" that was assumed to be in true in 1977. But the energy mix of the mid-1970s does not exist today. The least-cost unit is now a combined-cycle unit and not a combustion turbine. Theoretically, the combined cycle unit is more efficient and should not cost less than a combustion turbine on a per-kilowatt (kW) basis. BCP is also concerned that the combined revenue reconciliation process of the generation and energy function is just a means to shift more of the revenue requirement onto residential customers. (Ex. 189 at 9-12).

549. Staff discusses several alternative methodologies to those used in Nevada Power's MCSS. Yet, Staff recommends accepting Nevada Power's MCSS as it is largely consistent with the cost-of-service studies that the PUCN has accepted in previous cases, including those for Nevada Power's sister company, Sierra Pacific. (Ex. 199 at 1).

550. Staff struggles with the idea as to whether a general rate case is an appropriate venue for proposing major changes to the MCSS methodology, especially when such changes are technical in nature. If the Energy Choice Initiative is approved in 2018, it is reasonable to wait and address the MCSS study and revenue reconciliation in a broader manner. Staff suggests that an investigatory docket may be a better place for addressing issues in estimating incremental/marginal costs for Nevada Power to provide service, whether bundled or unbundled. (Ex. 199 at 2-3).

551. Staff states that there are many alternative methodologies, assumptions, and inputs (some of which are discussed in further detail below) that are equally reasonable and tenable to those used by Nevada Power. The PUCN has discretion to deviate from the class revenue requirement proposed by Nevada Power and determine appropriate class revenue allocation and rates. (Ex. 199 at 3). Staff's rate design is predicated on present rate revenues and maintains the present basic service and demand charges, while allowing volumetric rates to vary for a revenue requirement adjustment. Staff states that it is taking a less-contested approach in the hope of working with other parties in the spirit of the PUCN's Order in consolidated Docket Nos. 16-06006 through 16-06009. (Ex. 199 at 4). Despite Staff's recommendation to accept Nevada Power's MCSS, Staff states that there are several issues to be addressed in the MCSS and revenue reconciliation process as implemented by Nevada Power's proposed Statement O. The issues are (1) overstated marginal generation cost; (2) generation rescaling factor; (3) separate reconciliation of generation capacity and energy; and (4) whether O&M expenses should be assigned to unbundled energy revenue requirement. Individually and combined, the impact of these issues—all discussed in greater detail below—on the single family residential class is an $11 million to $28 million reduction in revenue requirement. (Ex. 199 at 21).

552. With respect to generation and energy revenue reconciliation in the MCSS, Staff states that Nevada Power overstates its generation capacity cost and, consequently, allocates a greater revenue requirement to the residential customer class than it should under the generation and energy combined revenue reconciliation process. (Ex. 199 at 11). As calculated by Staff under its separate revenue reconciliation process, revenue requirement for each residential customer class is reduced, while the revenue requirement for most commercial and industrial customer classes increases. This change does not affect each class percentage share of the generation capacity marginal cost pricing revenue (MCPR). Class revenue requirement allocation will not be affected by over- or under-estimation of a

marginal cost as long as each class's MCPR percentage share of each function does not change. (Ex. 199 at 13).

553. With respect to rescaling factor calculation for marginal demand costs in the MCSS, Staff states that the use of a generation rescaling factor overstates the generation capacity MCPR and, consequently, inappropriately allocates a greater revenue requirement to the residential customer class than it should under the generation capacity and energy combined revenue reconciliation process. If Nevada Power uses the generation rescaling factor, it should apply the same rescaling factor to developing the energy MCPR. (Ex. 199 at 13, 15).

554. With respect to generation and energy O&M expenses in the MCSS, Staff states that Nevada Power's Schedule H-2 and Certification Schedule I-2 present the unbundled revenue requirement to be recovered as unbundled revenue requirement for rate design for generation, transmission, and distribution. The annual BTER revenues appear carved out as the unbundled energy revenue requirement for the certification period and then subtracted from the unbundled generation revenue requirement, creating four unbundled revenue requirement areas for rate design: generation capacity, energy, transmission, and distribution. (Ex. 199 at 18-19). Staff recommends that a certain portion of the generation capacity O&M should be assigned to Energy to further reduce residential customer class revenue requirement under the separate revenue reconciliation process. When separating unbundled energy revenue requirement from unbundled generation capacity revenue requirement, a portion of the O&M costs should also be assigned as energy-related O & M costs. It is unreasonable to assume that there are no O&M expenses incurred in support of energy production including fuel and power procurements. (Ex. 199 at 18-20).

555. With respect to marginal capacity costs in the MCSS, Staff states that Nevada Power appears to have failed to develop the annual generation capacity cost from the annual fixed cost of owning and operating the new combined cycle unit. The annual generation capacity cost should be calculated as the difference between the installation cost of the combined cycle plant and the energy revenue that the combined cycle plant is expected to bring, as the calculation was performed in Sierra Pacific's integrated resource plan in Docket No. 16-07001 and Nevada Power's second amendment to its 2016-2035 integrated resource plan in Docket No. 16-08027. (Ex. 199 at 12).

556. Vote Solar agrees with Staff's analysis of the MCSS and the problems identified; but Vote Solar disagrees with Staff's recommendation that the PUCN overlook those problems. (Ex. 180 at 2).

Rebuttal

557. Nevada Power recommends approval of its certified MCSS as filed. The intervening parties have not presented sufficient evidence to warrant deviations from the established and approved

marginal cost of service methodologies utilized by Nevada Power in this proceeding. (Ex. 203 at 5, 27, 48). For the residential customer classes, Nevada Power proposes to defer the resolution of such issues as reflecting the blended full- and partial-requirement customers' costs of service in rates, as well as the elimination of the single-family residential subsidy, to future proceedings. Depending on the outcome of the Energy Choice Initiative, residential rate design (as well as rates for all other classes) will be a focal point of rate unbundling exercises in the next general rate case. Reconciliation remains the same, with revenue at full marginal cost reconciled to revenue at present rates. (Ex. 206 at 3-4).

558. With respect to generation and energy revenue reconciliation in the MCSS, Nevada Power recommends that the PUCN reject Staff's suggested separate revenue reconciliation process for generation and energy. The current combined revenue reconciliation is based on the interrelationship between generation capacity and energy investments made by Nevada Power. Generation and energy are objectively interrelated, and the costs that are allocated to customer classes should reflect this dynamic. By using the combined reconciliation process, customers pay just and reasonable prices that reflect the relationship between generation and energy. The only apparent justification Staff offers for separate reconciliation is to eliminate any possible over/under estimation in the allocation of class revenue from the embedded revenue requirement if the marginal cost is in error. However, Staff's proposed adjustments are also subject to error. Staff's concern is based on theoretical caution instead of evidence and should be rejected. (Ex. 203 at 50-52).

559. With respect to the rescaling factor calculation for marginal demand costs in the MCSS, Nevada Power recommends that the PUCN reject Staff's recommendation to remove the generation rescaling factor or "arbitrarily" apply it to marginal energy costs. (Ex. 203 at 5). Nevada Power recommends that the PUCN approve Nevada Power's use of a rescaling factor in the development of marginal demand costs in the MCSS. Rescaling is necessary to ensure that the final result reflects the cost of adding one kW of capacity to the overall system. The rescaling factor is used for development of each demand cost (distribution substation, distribution non-revenue feeder, transmission, and generation) in the MCSS to ensure that the marginal cost revenue equal the cost of adding one kW of capacity to the overall system. (Ex. 203 at 19).

560. With respect to general and energy O&M expenses in the MCSS, Nevada Power recommends rejecting Staff's recommendation to split Generation O&M costs to the Energy function in the MCSS. Nevada Power states that absent a change in the approved methodology for revenue reconciliation, there would be no impact of Staff's recommended change. Staff's suggestion is logically inconsistent as O&M is not recovered through the energy revenue requirement—the BTER—and therefore these

expenses should not be allocated away from generation and to energy. Staff's recommendation only addresses one side of the equation, instead of also identifying the generation capacity component of purchased power that goes into the energy revenue requirement. (Ex. 203 at 5, 17-18).

561. With respect to marginal capacity costs in the MCSS, Nevada Power disagrees with Staff's characterization that it failed to develop the annual generation capacity cost from the annual fixed cost of owning and operating a new combined cycle unit. Nevada Power developed the generation capacity using the installation cost of a combined-cycle generation unit. Previously, Nevada Power used a combustion turbine, but construction costs have decreased and the combined-cycle is now the least-cost unit. (Ex. 203 at 15). Nevada Power states that Staff's proposed adjustment to the marginal generation capacity cost is "inappropriate." Staff references a method by which an off-system market capacity price can be evaluated at certain hours, but this is not a viable alternative to providing true capacity and reserves. Nevada Power's analysis found that there were are no months in the period between 2018 and 2029 where a combined-cycle unit would have the opportunity to earn revenue from off-system sales that is in excess of the value of serving native load. (Ex. 203 at 15-17).

PUCN Discussion and Findings

562. The PUCN accepts Nevada Power's MCSS as filed for the reasons stated by Staff and outlined in Nevada Power's rebuttal testimony. The PUCN recognizes that there are potential modifications to the MCSS that may warrant additional investigation; but for the purposes of the instant docket, such modifications are unnecessary.

563. There are multiple future opportunities to review the MCSS methodology, including in the ongoing discussion of TOU rate proceedings in Docket No. 17-07026 and in the investigation into the effect of NEM customers on other customers in Docket No. 17-07013. The primary purpose of the MCSS is for use in rate design. Because Nevada Power has proposed in its rebuttal Statement O to essentially retain current class revenue requirement, the results of the MCSS are largely moot. With these considerations in mind, the PUCN finds that there is limited value in implementing mere suggestions for modifications at this time.

2. Future Embedded Cost of Service Study

Party Positions

564. Nevada Power provided a MCSS, which employs a methodology that is based upon the marginal cost methodology developed by National Economic Research Associates and derives marginal customer, facilities, energy, and demand costs for each of Nevada Power's bundled rate classes. The MCSS develops revenue at full marginal cost for each rate class. The MCSS describes how investments become basis for marginal costs to serve and inform the needed marginal revenue to

be recovered from each customer class. (Ex. 2 at 8; Ex. 169 at 5-6). Nevada Power states that because marginal costs never match Nevada Power's embedded revenue requirement, reconciliation must take place. Reconciliation occurs in Statement O in rate design, which Nevada Power provided in this case. (Ex. 169 at 5-6).

565. FEA recommends investigating the appropriateness of the additional layer of cost distinction in the marginal-to-embedded cost reconciliation in the next general rate case. Nevada Power's method of reconciling marginal costs to embedded costs for the test period is separated by cost function; that is, it is separated between distribution, transmission, and generation costs. However, FEA contends that the reconciliation method does not separate distribution costs into classifications, which would incorporate an additional distinction between costumer-related and demand-related costs. Nevada Power does not reconcile the customer-related marginal costs strictly to customer revenue requirement, but instead lumps together all distribution costs that are both demand-related and customer-related, which muddies the cost allocation differences that are created when these assets are separately classified as customer- versus demand-related in the MCSS. (Ex. 182 at 2).

566. BCP recommends requiring an embedded cost of service study using a four-coincident-peak allocator for functionalized generation and transmission costs and a non-coincident-peak allocator for functionalized distribution costs in Nevada Power's next general rate case. (Ex. 188 at 2). BCP states that Nevada Power alleges that there is a residential subsidy of $53.1 million, based solely on the result of the MCSS. An embedded cost of service study would likely produce different results. BCP urges the PUCN to consider multiple cost-of-service methodologies to set rates and determine whether there is a residential subsidy. (Ex. 188 at 10-12).

567. BCP explains that Nevada is one of only 9 states that rely solely on a MCSS to determine customer class cost responsibility. Nevada is the only one of these states to use both an historic test year (as required by statute) and marginal cost of service. There is inconsistency when using both recorded numbers and projected numbers to allocate revenue requirement to customers. (Ex. 188 at 10, 13-14). Moreover, adoption of the marginal cost of service methodology occurred at a time when per-customer usage was increasing, not decreasing, as it has been over the past 40 years. Recent research indicates that customers respond to average prices, not marginal prices or expected prices. (Ex. 188 at 10 -11, 17-18).

Rebuttal

568. Nevada Power opposes including an embedded cost of service study in its next general rate case. According to Nevada Power, marginal cost of service provides customers with meaningful forward price signals. The marginal cost of service helps customers, including residential customers,

respond to and adapt to changing price signals, by conveying cost information. An embedded cost of service study should not be used as a check on marginal cost analyses. The PUCN has previously considered and rejected embedded cost study proposals. (Ex. 206 at 7-12, 17, 23).

PUCN Discussion and Findings

569. Doubt and disagreement about the reliability and overall accuracy of the MCSS appeared throughout this instant docket, as well as in Sierra Pacific Power's general rate case in Docket Nos. 16-06006 through 16-06009. We cannot be afraid to learn more information or to consider new ways and methodologies of analyzing rate making.

570. As Nevada modernizes its electric system, with advancements in NEM, battery storage, and electric vehicle usage ongoing, old ways and methodologies *must* be challenged and thoughtfully reviewed to ensure they still work in a changing world. Accordingly, the PUCN agrees with BCP and finds that it is both reasonable and prudent to include an embedded cost of service study, along with the MCSS, in Nevada Power's next general rate case. The PUCN also directs Sierra Pacific Power to file an embedded cost of service study, in addition to a MCSS, in its next general rate case.

571. In making these findings and directives, the PUCN acknowledges that it has historically relied upon marginal cost of service studies for rate design and has also previously declined to require embedded cost of service analyses. With advancements in NEM, battery storage, and electric vehicle use, now is the right time for a new study.

F. RATE TILT

Party Positions

572. Nevada Power includes in its filing a rate tilt analysis for the large commercial and industrial classes pursuant to a directive in the PUCN's Order in Docket Nos. 14-05004 and 14-05005. Exhibit Pollard Cert-4 summarizes the updated results of the rate tilt analysis. The updated results included in the Certification, similar to the initial results, show a significant amount of rate tilt is preferred when designing TOU demand and energy rates. (Ex. 171 at 38; Ex. 172 at 25, Ex. Pollard-Cert-4).

573. Staff recommends accepting Nevada Power's rate tilt analysis as compliant with the Rate Tilt Directive contained in the Order issued in Docket Nos. 14-05004 and 14-05005. (Ex. 192 at 15).

PUCN Discussion and Findings

574. The PUCN finds that Nevada Power provided an analysis of rate tilt for the large commercial and industrial classes and provided supporting information justifying the resulting percentages for those particular classes, as required by the PUCN's Order in Docket Nos. 14-05004 and 14-05005. The PUCN further finds that it would be beneficial to have similar justification for Nevada Power's analysis of rate tilt in future filings. Accordingly, the PUCN directs Nevada Power to again specifically

address rate tilt for the large commercial and industrial classes and provide supporting information justifying the resulting percentages for those particular classes in the next general rate case.

G. Optional Critical Peak Pricing and Demand Use Schedule for Residential Classes

Party Positions

575. Nevada Power proposes adding critical-peak-pricing and planned-demand-use tariffs for its residential customers. (Ex. 162 at 3).

576. Vote Solar contends that Nevada Power's proposal for new critical-peak-pricing and planned-demand-use tariffs has not been studied in detail. Critical-peak-pricing rates can, if designed well, produce significant customer response, especially if these rates are combined with technology support. However, Nevada Power did not present the necessary details in this case. Vote Solar further states that Nevada Power's planned-demand-use proposal appears similar to Nevada Power's proposed TOU rates proposal and is therefore superfluous. (Ex. 179 at 34-35).

577. Staff recommends requiring Nevada Power to offer an optional critical-peak-pricing schedule to all residential rate classes. Different types of TOU rate offerings will appeal to different customers, which should result in increased participation benefitting the grid. Such rates should be effective no later than June 1, 2018. (Ex. 190 at 8-9).

Rebuttal

578. Nevada Power argues that the proposed new rates, critical-peak-pricing and planned-demand-use tariffs, are time-variant rates that would help during peak demand periods. It is important for optional offerings to be based on costs. Nevada Power contends that two new optional tariffs would provide cost-based price signals that would likely result in savings for both the grid and for individual customers. (Ex. 206 at 32).

PUCN Discussion and Findings

579. As previously discussed in this Order, the PUCN defers all discussion of TOU rates, including critical-peak-pricing and planned-demand-use tariffs, to Docket No. 17-07026. The PUCN directs Nevada Power to provide (or update) its critical-peak-pricing and planned-demand-use tariff proposal in that docket.

H. NRS Chapter 704B Customer Senate Bill 123 Regulatory Asset Rate

Background

580. The Nevada State Legislature passed Senate Bill (SB) 123 in 2013 and essentially mandated the retirement of coal-fired generating facilities in Nevada. It was last codified in NRS 704.7316. Pursuant to terms and conditions either stipulated to by the parties, *i.e.*, MGM and Caesars, or Ordered

by the PUCN, *i.e.*, Wynn, businesses that chose to exit Nevada's regulatory compact with Nevada Power remained liable for a portion of SB 123 costs.

Party Positions

581. Nevada Power states that the SB 123 regulatory asset rate consists of two charges and applies to customers who have exited bundled service pursuant to NRS Chapter 704B. (Ex. 171 at 15-16). The calculation of the rate can be found in Statement O, work paper 1, page 6. (*See* Ex. 4 and Ex. 158 and Ex. 159 at Statement O).

582. MGM contends that it is unfair for Nevada Power to seek an SB 123 regulatory asset charge, which is a $3.00-per-megawatt-hour (MWh) charge from MGM. MGM maintains that it prepaid a sufficient amount in its $86 million impact fee to hold remaining Nevada customers harmless until 2022. So long as Nevada Power's revenue requirement does not increase, MGM argues that remaining bundled customers will not be harmed by MGM's departure pursuant to NRS Chapter 704B. If the revenue requirement is reduced, bundled customers and/or shareholders will derive benefits from MGM's advance overpayment of current BTGR. MGM contends that SB 123 Regulatory Asset Charge being sought is discriminatory because it will not be applied to all bundled and applicable Distribution Only Customers (DOC). Nevada Power provides no analysis to show the costs from the SB 123 regulatory asset charge have not already been paid by MGM. (Ex. 197 at 1-6; Tr. at 1612, 1701; 1935-94).

583. Wynn disagrees with Nevada Power's allocation of costs in the SB 123 regulatory asset charge. According to Wynn, the proposed charge violates the principle of the non-bypassable charge established in Docket No. 15-05006. Wynn contends that Nevada Power's work papers were not sufficiently detailed to determine how Nevada Power arrived at the annual SB 123 regulatory asset revenue requirements. Impact fee payments related to the BTGR have already been paid by Wynn and provide sufficient revenues to cover its cost-of-service-based share of these costs through the next rate-effective period. (Ex. 195 at 2-6; Tr. at 1590, 1660).

584. Wynn contends that the SB 123 regulatory asset costs should not be allocated 100 percent by energy allocation. Instead, the marginal cost of service study (MCSS) should be used to allocate the costs. The MCSS is the existing method that the PUCN has used in the past, the method that Nevada Power is recommending be used to allocate costs to bundled customers, and the method that the PUCN will likely use to allocate costs to bundled customers in the next general rate case. Wynn states that it makes sense for the MCSS to be used to allocate the SB 123 costs as well. (Ex. 195 at 13-14).

585. Wynn further contends that if an SB 123 regulatory asset charge is approved, Wynn a rate design of a fixed dollar-per-month charge is appropriate. The vast majority of the SB 123 costs do not

vary in any appreciable way with the number of kilowatt-hours (kWh) generated, but occur primarily as a function of the existence of the plants, the hours of operation, and the passage of time. (Ex. 195 at 16-17).

586. Wynn requests that the currently-proposed surcharge of approximately $1,698,972 not be assessed against it. Wynn, Post-Hearing Brief at 1 (December 15, 2017).

587. Caesars objects to the SB123 regulatory asset charge because this charge double-recovers the same capital costs that Caesars has already committed to pay as part of its NRS Chapter 704B impact fee for the next 6 years. (Ex. 184 at 3).

588. BCP states that Nevada Power should be required to flow back revenue credits from NRS Chapter 704B exit customers to all customers. Nevada Power proposes to limit the credit to customers not receiving a subsidy, but BCP questions whether a subsidy even exists. (Ex. 188 at 20-21).

589. Staff recommends approving the preferred rate design methodology proposed by Nevada Power in its original filing. Staff states that Nevada Power's proposal is reasonable; but Staff suggests that the SB 123 regulatory asset charge be set at $0 (zero). With all of the adjustments Staff proposes to Nevada Power's revenue requirement, State states that the SB 123 regulatory asset charge becomes a non-issue in this case and that Nevada Power's present rate revenue will cover the costs proposed in the SB 123 regulatory asset charge. (Ex. 192 at 3, 5-6, 13).

Rebuttal

590. Nevada Power opposes setting the SB 123 regulatory asset charge at $0 (zero). Nevada Power maintains that it has fully justified inclusion of the underlying regulatory asset cost in rate base, and the proposed SB 123 regulatory asset charge is calculated as prescribed in the applicable exit orders for each of the departed NRS Chapter 704B customers to pay their fair share. That Nevada Power has committed to do more with the current revenue for the rate-effective period does not change this fact.

591. Nevada Power disagrees that the impact fees paid in the NRS Chapter 704B dockets are sufficient to cover the SB 123 costs associated with the decommissioning and remediation of Reid Gardner and Navajo generating stations. Nevada Power states that the majority of the upfront impact fees is the difference between the exiting customer's revenue as a fully-bundled customer and its DOS and transmission revenue for a certain number of years. The costs associated with the SB 123 charges were not included in bundled rates during Wynn, MGM, or Caesars dockets. Therefore, Nevada Power asserts that the impact fee for each customer does not include the SB 123 costs. (Ex. 206 at 36-37; Tr. at 1590, 1612, 1660, 1701, 1935-1994).

592. Nevada Power argues that the SB 123 revenue requirements credit should not be applied to reduce the revenue requirement of all classes including the single family residential class. Because the

single family residential class continues to enjoy the residential subsidy, customers should not receive a rate reduction. The credit should be used to reduce the single family residential subsidy. (Ex. 206 at 38). Nevada Power does not oppose the suggestions that the SB 123 regulatory asset charges can be recovered on a fixed dollar-per-month basis. (Ex. 206 at 43).

PUCN Discussion and Findings

593. The PUCN finds that the **SB 123 regulatory asset charge proposed to be applied to MGM and Caesars shall be set to $0 (zero).** Pursuant to the stipulations accepted and approved by the PUCN in Docket Nos. 15-05017 and 16-11034, respectively, MGM and Caesars agreed to pay their fair share of the net book value of Reid Gardner through December 31, 2022, and their fair share of decommissioning and remediation costs of Reid Gardner until those costs are fully recovered from ratepayers.[22] MGM and Caesars agreed that they should not avoid responsibility for their respective share of these costs to the burden of remaining ratepayers in compliance with NRS Chapter 704B. Given that Reid Gardner decommissioning and remediation expenses will be deferred for recovery until 2020, there will be a nominal reduction in the overall revenue requirement, and no costs associated with that expense will be borne by MGM or Caesars in this case. MGM and Caesars shall be treated like all other ratepayers.

594. MGM and Caesars' argument that the BTGR portions of the impact fees were based on rates that included Reid Gardner in the calculation of BTGR rates has merit. MGM has paid approximately $86 million in impact fees. Caesars has (or will) pay approximately $44 million in impact fees. MGM and Caesars' BTGR portions of their respective regulatory liabilities in their impact fees are included as an offset to rate base and decrease the obligations of remaining fully-bundled retail ratepayers. Remaining customers will not be paying increased costs as a result of MGM and Caesars' departure, and the return of and return on the net book value of Reid Gardner is absorbed in the adjusted revenue requirement.

595. Similarly, **Wynn's SB 123 liability shall also be set to $0 (zero).** Nevada law requires that no disparity or discrimination occur in the NRS Chapter 704B process—to anyone. *See* NRS 704B.3107(b)(1). The NRS Chapter 704B process is largely unique to Nevada, and there is not much of a roadmap on these issues. Predicting the future and estimating costs is not an exact science, and the PUCN is committed to addressing any errors or concerns to ensure that the exiting process is consistent and as fair as possible. Irrespective of the existence of a stipulation or not, Wynn should

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[22] Navajo is not addressed in this discussion because the plant is still in operation, and no stranded net book value or decommissioning and remediation costs are included in this docket.

not be charged a fee as a result of its exit that no other entity is charged, or has not already paid. Accordingly, the PUCN finds that Wynn's argument has merit. Equity and fundamental fairness of process warrant eliminating any further collection of SB 123 charges from Wynn in this proceeding. Wynn has already paid approximately $15 million in impact fees to ensure the public is not harmed by its departure.

596. At some point, the divorce from ongoing liability for generation assets needs to become final.[23] The PUCN defers all remaining discussions and findings regarding Wynn's NRS Chapter 704B impact fees to the February 1, 2018, proceedings scheduled in Docket No. 15-05006.

I. Switch and Distribution Only Service (DOS) Charges

Party Positions

597. SEA alleges on behalf of its member client Switch that the Distribution Only Service (DOS) charges sought by Nevada Power in this case violate the terms of the stipulation it entered into in Docket No. 14-11007. SEA contends that the DOS charges being imposed by Nevada Power constitute non-bypassible charges and/or fees, which are covered by the approximately $27 million impact fee. Specifically, SEA cites to paragraph 3 of the stipulation that provides that Switch "shall not be responsible for the payment of other non-bypassable rates or fees other than those specifically delineated" in the stipulation. SEA, Post-Hearing Brief at 16 (December 15, 2017).

598. SEA maintains that a portion of the DOS charge being assessed against it funds an interclass residential subsidy that should only be applied to bundled service customers. As a DOS customer of Nevada Power, SEA argues that this charge should not be applied to Switch.

PUCN Discussion and Findings

599. It is the PUCN's understanding that any interclass subsidy is embedded into the DOS rate and that the DOS charge *is not* a non-bypassable charge unique to Switch.

600. All DOS customers, including NRS Chapter 704B businesses such as MGM, Caesars, and other entities in Southern Nevada such as the Southern Nevada Water Authority, who are only distribution/ transmission customers of Nevada Power continue to pay this charge without objection for the service Nevada Power continues to provide them, even though their generation is purchased from another source. It appears proper (upon initial review).

601. However, as discussed in other areas of this Order, the PUCN remains concerned regarding the overall fairness and equity of the NRS Chapter 704B process. To the extent Switch alleges that the

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[23] Switch has not raised a specific issue in these proceedings regarding SB 123 non-bypassable charges. If any disparity exists between Switch and the other NRS Chapter 704B customers on this issue, the PUCN will correct it. However, any SB 123 charges are covered in Switch's already-paid impact fee.

terms of its stipulation are being breached, the PUCN will review the allegations, schedule additional proceedings, and hear argument, and possibly testimony, in Docket No. 14-11007, if either Switch or Staff make such a request to ensure that the terms of the stipulation are being faithfully and properly interpreted and applied.

602. The current DOS charge calculation has been in place for decades and whether or not it unfairly subsidizes Southern Nevada residential customers or a subsidy exists at all remains unsettled amongst the parties. Indeed, BCP maintains that no residential subsidy exists. Accordingly, and as also discussed in other portions of this Order, in the interest of better understanding the relative costs of providing service to different customer classes, the PUCN has directed Nevada Power to complete an Embedded Cost of Service Study to compare with the Marginal Cost of Service Study results in Nevada Power's next general rate case.

J. The Alleged Residential Subsidy

Party Positions

603. Nevada Power's proposed rates are presented in its most current Statement O and do not include rates designed to reduce or eliminate the existing interclass residential subsidy. (Ex. 171 at 2, 5, 7 and Ex. 172 at 4).

604. Walmart states that if the PUCN approves a lower revenue requirement for Nevada Power, the first $54.4 million of any reduction should be used to reduce the interclass subsidy and applied only to customer classes that pay subsidies to other classes through the interclass rate rebalancing rate. Walmart argues that any reduction in excess of $54.4 million should be applied pro rata to all customer classes. (Ex. 194 at 4). Walmart advocates that rates be set based on the utility's cost of service for each rate class, producing equitable rates that reflect cost causation, send proper price signals, and minimize price distortions. (Ex. 194 at 5).

605. Walmart notes that the PUCN previously recognized the problematic nature of an apparent interclass subsidies in Docket 14-05004. Nevada Power's current proposed interclass rate rebalancing shows that LGS-2S subsidy revenue requirement would be approximately $9.7 million (or $0.00409/kWh) and that the LGS-3S revenue requirement be approximately $3.5 million (or $0.00389/kWh). (Ex. 194 at 6-7).

606. Wynn recommends that measured steps be taken toward cost based rates in an effort to minimize interclass subsidies over time. (Ex. 195 at 8).

607. SNGG stresses the importance of cost-based rates and suggests that if a decreased revenue requirement is approved by the PUCN, it presents an opportunity to eliminate or substantially reduce the interclass subsidy without causing rate increases to the residential class. (Ex. 178 at 3). SNGG

states that Nevada Power's Statement O—ECIC (at NRS revenue requirement) technically complied with the Order in Docket No. 14-05004, but fails to present a viable solution. (Ex. 178 at 11). SNGG recommends that the PUCN reject Nevada Power's suggestion that any movement toward cost-based rates should only occur in the event of a rate increase scenario and argues that the opposite is true. The PUCN should order an appropriate overall revenue requirement decrease, and that decrease should be used to eliminate or significantly reduce the existing subsidy. (Ex. 178 at 13-14).

608. FEA recommends a correction to Nevada Power's calculation of the interclass rate rebalancing charge embedded in the BTGR. Nevada Power made a miscalculation by failing to include the full kWh sales for certain classes. If the PUCN finds that the interclass rate rebalancing charge is reasonable, the error should be corrected. (Ex. 182 at 2-3).

609. BCP states that there is inadequate evidence to credibly assert the existence of a residential subsidy. None of the parties that assert the existence of the subsidy question the accuracy of the MCSS. It is important to correctly allocate costs to customer classes, but reliance on one type of cost-of-service study to do so puts too much faith in one type of study. To correctly allocate costs, Nevada Power should correct the errors in its MCSS, rely upon actual results of operations required by NRS 704.110(3) to allocate historical test year costs, and perform an embedded cost of service study. (Ex. 189 at 3-4).

610. Staff does not recommend any changes to the MCSS at this time, but notes that while the results are sensitive to assumptions made, issues to be addressed in Nevada Power's cost-of-service study and revenue reconciliation process reduce the generation and energy allocated to the single-family residential class. Staff suggests that the amount of a residential subsidy may not be as great as claimed by Nevada Power. (Ex. 199 at 21).

Rebuttal

611. Nevada Power proposes deferring elimination of the single-family residential subsidy to future proceedings. Depending on the outcome of ECI, residential rate design will be a focal point of rate unbundling exercises in the next general rate case. In the meantime, Nevada Power states that the single-family residential subsidy will be reduced, but not eliminated, by holding single-family residential rates at current levels and passing incremental revenues through to remaining non-subsidized residential and commercial customers. (Ex. 206 at 3-4). Nevada Power states that SNGG does not offer a better solution for setting class revenue requirement with no change in overall revenue requirement. If total revenue requirement does not change, someone's rates have to go up for others' rates to go down. (Ex. 206 at 27-28). Nevada Power suggests that Staff's position is inconsistent with

past testimony, stating that Staff has argued that there is a significant single-family residential subsidy in every prior general rate case. (Ex. 2-6 at 28).

PUCN Discussion and Findings

612. Whether a residential subsidy truly exists or not is still the subject of debate. The MCSS shows one exists. As previously discussed in this Order, the PUCN accepts it as reasonable. However, as BCP has argued, it may be a product of flaws in the MCSS. The Embedded Cost of Service Study, as directed by the PUCN in this Order, may shed further light on this issue in the next general rate case. Accordingly, the PUCN finds that the interclass revenue rebalancing shall be calculated as filed in Nevada Power's rebuttal Statement O and as revised for any adjustments to revenue requirement. If a subsidy does exist in the current rate paradigm that benefits working Nevada families, the PUCN is reluctant to disturb it at this time without more compelling evidence and analysis.

K. Unbundled Rates for Residential Customers

Party Positions

613. Nevada Power filed rates that do not separate distribution costs into demand-related and customer-related. Distribution costs are not separately reconciled. (Ex. 3 at Statement H; Ex. 157 at I-CERT).

614. FEA recommends investigating the appropriateness of separating Nevada Power's distribution costs into two categories—demand-related and customer-related—to reconcile marginal costs and embedded costs. Because Nevada Power does not separately reconcile marginal demand-related costs to embedded demand-related costs, it is necessary to estimate these costs. Absent a study, FEA states that it is unclear what the appropriate distribution costs are for cost allocation. (Ex. 182 at 2, 7-8).

615. Staff supports FEA's recommendation to investigate the appropriateness of separating distribution costs into demand-related and customer-related costs so that the costs are separately revenue-reconciled. Distribution cost allocation will become more relevant if Nevada Power is required in the future to provide unbundled services through the Energy Choice Initiative. However, Staff states that Nevada Power's current accounting system cannot accommodate separating distribution costs into demand-related and customer-related costs at this time. (Ex. 200 at 9).

Rebuttal

616. Nevada Power disagrees with the recommendation to unbundle the distribution revenue requirement into demand-related and customer-related costs. Unbundling distribution revenue requirement into its subcomponents is both inappropriate and logistically inefficient. To perform a separate reconciliation process for each of these components, an embedded revenue requirement by component would have to be developed. Nevada Power's accounting system is set up to collect data

at the gross level by the generation, transmission, and distribution functions. Distribution accounts do not contain, nor are they required to contain, the type of plant or expense detail needed to separate the accounts into the subcategories of customer costs, facilities costs, and distribution demand. To do so, a cost review on a project-by-project basis would need to be performed to attain the granularity necessary to develop separate embedded revenue requirements for distribution service components. (Ex. 203 at 7, 54-57).

PUCN Discussion and Findings

617. The PUCN declines at this time to require Nevada Power to separate distribution costs into demand-related and customer-related costs so that the costs are separately revenue-reconciled. Nevada Power's current accounting system is not able to accommodate a request to separate out these distribution costs. However, the PUCN encourages Nevada Power to examine options to implement a requirement to separate out distribution costs in the future.

L. ZERO BASE TARIFF GENERAL RATE (BTGR) FLOOR

Party Positions

618. Nevada Power states that Statement O, Summary of Proposed Rates (Bundled), provides a summary of rates for all classes. This schedule contains negative Base Tariff General Rate (BTGR) rates for certain customer classes in certain seasons. (Ex 4. at Statement O; Ex. 157 at Statement O).

619. Staff recommends requiring Nevada Power to implement a BTGR rate floor of zero. Staff states that it does not believe that any BTGR should be negative. Staff states that the rates that come out of these proceedings should reflect the costs that each customer class imposes on the system. The negative rates are a byproduct of the method Nevada Power uses to calculate rates. The rates for all times of the year are calculated based upon marginal energy costs and marginal demand and capacity costs. When a specific customer class's rates are calculated, the embedded BTER is subtracted from the proposed rate, and sometimes this leads to a negative rate.

620. According to Staff, negative rates suggests that for Nevada Power to recover the assigned costs to a particular customer class, rates in that class at other times of the year increase to cover the negative rate. While this does not mean that Nevada Power is using other customer classes to pay the negative rate cost, Staff is concerned that the negative rate is confusing for customers. Setting a zero BTGR floor would solve any concerns customers may have that negative rates are the result of a different customer class paying for those costs. (Ex. 192 at 2, 14-15).

Rebuttal

621. Nevada Power disagrees with Staff's recommendation. Nevada Power does not think a zero BTGR floor is necessary. Nevada Power always attempts to minimize negative BTGRs due to their

seemingly illogical results. However, a negative BTGR is a valid study result. Furthermore, for two water-pumping classes (the LGS-2S-WP and LGS-3S-WP classes), a negative BTGR is unavoidable, due to the way rates are calculated for those classes. Therefore, requiring a floor of zero for the BTGR would lead to more complexity and confusion than allowing a negative BTGR. Similarly, customers who opt into the Electric Vehicle Recharge Rider (an opt-in tariff that provides for a ten-percent discount to the off-peak total rate to encourage customers to charge their electric vehicles during the lowest-cost 10:00 p.m.-6:00 a.m. period) could also face a negative BTGR with the way the tariff is structured. Again, requiring a zero floor would make it more, not less, confusing and complex for these customers. (Ex. 203 at 45-47).

PUCN Discussion and Findings

622. The PUCN finds that implementing a zero BTGR floor is unnecessary at this time. For two water-pumping classes (the LGS-2S-WP and LGS-3S-WP classes), and for customers that opt in to the Electric Vehicle Recharge Rider, a negative BTGR may be unavoidable, due to the way that rates are calculated for those classes. Requiring a floor of zero for the BTGR would lead to more, not less, complexity and confusion than allowing a negative BTGR.

M. Renewable Portfolio Standard (RPS) Adder

Party Positions

623. Nevada Power included, as part of the overall MCSS, a Renewable Portfolio Standards (RPS) adder. (Ex. 169 at I-CERT; Ex. 170 at I-CERT).

624. FEA recommends rejecting Nevada Power's proposed RPS adder of $9.91 per MWh and instead order that the adder be set at $0.00 per MWh, to reflect Nevada Power's marginal RPS costs. FEA states that the adder should be set at zero because Nevada Power's large balance of renewable energy credits leads to the marginal renewable energy cost of one additional kWh equaling zero. (Ex. 182 at 2).

625. BCP recommends rejecting FEA's recommendation to set the marginal cost of the RPS adder to zero, especially in light of the fact that Nevada Power's customers are paying more than $215.00 per MWh for renewable energy credits for certain projects. Nevada Power's current RPS adder attempts to account for the substantial 'out-of-the-money' contracts in the MCSS. If the energy and capacity continue to have a combined reconciliation and the PUCN accepts FEA's recommendation, BCP contends the result will be the allocation of more costs to residential customers in the MCSS. (Ex. 189 at 16-18).

Rebuttal

626. Nevada Power recommends rejecting FEA's recommendation to set the RPS adder to zero. Nevada Power recommends approving its RPS adder of $9.91 per MWh in the MCSS. Nevada Power has secured resources to comply with Nevada's RPS. However, even with resources under contract into future years, there are costs for the renewable resources. During the rate-effective period, the compliance requirement will grow to 22 percent. Nevada Power disagrees with FEA's assertion that Nevada Power is investing beyond the RPS compliance goals set in statute. (Ex. 203 at 5, 7-10).

PUCN Discussion and Findings

627. The PUCN finds that Nevada Power's use of the $9.91 RPS adder in its MCSS is valid and reasonable. Costs are incurred for renewable portfolio compliance, and there will be new RPS compliance costs incurred by Nevada Power during the rate-effective period. The use of the adder is appropriate to reflect the impact of such costs in rate design.

N. NEVADA POWER RENEWABLE ENERGY LABOR EXPENSES

Party Positions

628. Nevada Power included renewable labor costs from its Renewable Energy Department in its initial and certification filings. (Ex. 169 at H-CERT; Ex. 170 at H-CERT).

629. Vote Solar recommends rejecting Nevada Power's proposed allocation of the labor costs of the Solar, wind, and water Renewable Energy Department. Vote Solar states that these labor costs are treated as customer service costs in Nevada Power's filings when they should be treated as compliance costs. Vote Solar recommends putting these costs into the BTER. (Ex. 179 at 36, 38).

630. FEA disagrees with Vote Solar's recommendation to reallocate labor costs of solar, wind, and water Renewable Energy Department from customer service to compliance costs. (Ex. 183 at 2-3).

Rebuttal

631. Nevada Power disagrees with Vote Solar's recommendation regarding the solar, wind, and water Renewable Energy Department labor costs. Nevada Power states that the labor costs of the solar, wind, and water Renewable Energy Department are not RPS compliance costs. The labor costs are appropriately classified as customer service costs. (Ex. 203 at 10-12).

PUCN Discussion and Findings

632. The PUCN finds that the allocation of solar, wind, and water Renewable Energy Department labor costs are reasonable and properly classified as customer service costs. The Basic Tariff Energy Rate (BTER) is set quarterly to recover the costs of fuel and purchased power. It is not the mechanism for recovering solar, wind, and water Renewable Energy Department labor costs. These costs belong where they are.

IX. COMPLIANCE ITEMS AND DIRECTIVES

All directives, compliance items, and reductions contained within this Order shall become effective as soon as possible, and upon completion of the appropriate tariff changes being filed by Nevada Power with the PUCN.

X. CONCLUSION

Given the discussion and findings made above, the PUCN orders the general rate applications filed by Nevada Power GRANTED IN PART AND DENIED IN PART.

It is so ORDERED.

DATED this 29th day of December 2017.

By: ______________________________

JOSEPH C. REYNOLDS
Chairman and Presiding Officer

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ANN C. PONGRACZ
Commissioner

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BRUCE H. BRESLOW
Commissioner

Attest: ______________________________

TRISHA OSBORNE

Assistant Commission Secretary

Dated: Carson City, Nevada

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(SEAL)