BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

In re Application of NEVADA POWER COMPANY for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.	)	Docket No. 01-10001
In re Application of NEVADA POWER COMPANY for approval of new and revised depreciation rates.	)	Docket No. 01-10002

At a general session of the Public Utilities Commission of Nevada, held at its offices on March 27, 2002.

PRESENT: Chairman Donald L. Soderberg
Commissioner Richard M. McIntire
Commissioner Adriana Escobar Chanos
Commission Secretary Crystal Jackson

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

I. PROCEDURAL HISTORY

1. On October 1, 2001, Nevada Power Company ("NPC") filed an Application, designated as Docket No. 01-10001, with the Commission. This Application is for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers within its service territory in the amount of $42,719,000.

2. On October 1, 2001, NPC filed an application, designated as Docket No. 01-10002, with the Commission. In this application, NPC seeks approval of new and revised depreciation rates for a single component of general electric plant related to computers. NPC also requested that this application be consolidated with Docket No. 01-10001.

3. These Applications are filed pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), Chapters 703 and 704, including but not limited to NRS 704.100.

4. The Commission issued a public notice of this Application in accordance with State law and the Commission's Rules of Practice and Procedure.

5. Petitions for leave to intervene have been granted to the Colorado River Commission of Nevada ("CRCN"), the Utility Shareholders Association of Nevada, Inc. ("USAN"), the Department of Energy ("DOE"), MGM Mirage ("MGM"), the Nevada Energy Buyers Group ("NEBG"), the Nevada Coalition of Commercial Energy Users ("NCCEU"), the Southern Nevada Water Authority ("SNWA"), the Nevada Independent Energy Coalition ("NIEC"), the Chemical Lime Company ("Chemical Lime"), Southern Nevada Homebuilders Association and Carina Corporation ("SNHBA and Carina"), Mirant Las Vegas, LLC and Mirant Americas Energy Marketing, LP ("Mirant") and the Clark County School District[1]. The Regulatory Operations Staff of the Commission ("Staff") and the Attorney General's Bureau of Consumer Protection ("BCP") participate as a matter of right.

6. On October 5, 2001, the Commission issued an Order consolidating Docket Nos. 01-10001 and 01-10002.

7. A prehearing conference in these matters was duly noticed and held on October 29, 2001. On November 7, 2001, the Commission issued Procedural Order No. 1 outlining the procedural schedule for these matters.

8. Pursuant to NAC 703.2461, NPC filed its Certification on December 21, 2001.

9. Duly noticed consumer sessions were held as follows: on January 15, 2002 and January 22, 2002 in Las Vegas, January 22, 2002 in Henderson, and on January 28, 2002 in Las Vegas.

10. On January 15, 2002, the BCP filed a Motion to Compel Discovery and for Extension to File Supplemental Testimony ("BCP Motion") in Docket No. 01-10001. On January 18, 2002, NPC filed its Response to the BCP Motion. On January 22, 2002, the BCP filed their Reply. On January 17, 2002, the Commission granted the BCP Motion pending a response.

11. On January 22, 2002, MGM filed a Motion to Compel Discovery and for Extension of Time to File Supplemental Testimony; Joinder in the Motion Filed by the BCP Concerning the Same Subject Matter ("MGM Motion"). On January 25, 2002, the Commission granted in part, and denied in part the MGM Motion. On January 28, 2002, NPC filed its Response to the MGM Motion.

---

[1] The Petition for Leave to Intervene of Clark County School District was late-filed on February 4, 2002, and therefore was not granted until February 19, 2002.

12. On January 10, 2002, MGM filed a Motion to Consolidate Rate Design Hearings and Establish a Date Certain for Hearing of Rate Design Issues ("Rate Design Motion").

13. MGM also filed on January 10, 2002 a Stipulation to Consolidate for Hearing Rate Design Issues and Set a Date Certain for Hearing ("MGM Stipulation"). This MGM Stipulation contained the same request and provisions as laid out in the Rate Design Motion. The Stipulation was signed by MGM, Smith's Food and Drug Stores, Clark County, NPC, Staff, BCP, USAN, DOE, Chemical Lime, Mirant, SNHA, SNWA, CRCN, NCCEU, the City of Las Vegas, NEBG, NIEC and Sempra Energy Solutions. Pursuant to a request by the CRCN, a special provision was provided for in the Motion regarding Intervenor Testimony on the "Hoover B" contracts, and that provision is incorporated in the Stipulation by reference.

14. On January 23, 2002, the Commission issued Procedural Order No. 2, granting the Rate Design Motion and approving the MGM Stipulation. A consolidated hearing on the issue of rate design was scheduled for February 21, 2002, and a procedural schedule was outlined.

15. On January 28, 2002, Staff filed a Motion to Strike Portions of the Pre-filed Testimony of Nevada Power Company's Witnesses Ruelle and Brown ("Staff Motion to Strike") in Docket No. 01-10001. On January 31, 2002, the Commission issued an Order Granting the Motion for Shortening Time, providing until 5:00 p.m., February 1, 2002, for responses to be filed. On January 28, 2002, BCP filed its Joinder to the Staff Motion to Strike. On January 30, 2002, NPC filed its Response to the Staff Motion to Strike. On January 31, 2002, MGM filed a Joinder to the Staff Motion to Strike. On January 31, 2002, Staff filed its Reply. On February 1, 2002, the Commission issued an Order Granting Staff's Motion to Strike Testimony.

16. On February 4, 2002, a duly noticed hearing was held. The hearing was continued on February 5 through 8, February 12 through 14, February 19, February 21 and February 28, 2002. There were 122 exhibits admitted into evidence and 1631 pages of testimony.

17. On February 12, 2002, SNHBA and Carina filed a Petition to Late File Testimony ("SNHBA Petition") in Docket No. 01-10001. SNHBA and Carina request leave to file testimony dealing with Rule 9 issues. On February 14, 2002, the Commission issued Procedural Order No. 3 shortening the time for Responses and Reply to the SNHBA Petition. On February 15, 2002, the BCP filed its Response to the SNHBA Petition.

18. On February 15, 2002, NPC filed a Motion to Strike Portions of the Testimony of William B. Marcus and Anne-Marie Bellard ("Rule 9 Motion") and for an Order Shortening Time in Docket No. 01-10001. On February 19, 2002, Staff filed its Late-Filed Opposition to the SNHBA Petition, SNHBA and Carina filed their Reply and Response to NPC's Rule 9 Motion, and Staff also filed its Opposition to NPC's Rule 9 Motion. On February 20, 2002, the Commission issued Procedural Order No. 4 denying the petition of SNHBA and Carina and granting the Rule 9 Motion of NPC. The Commission ordered that all issues relating to changes to Rule 9 be stricken from this proceeding and addressed in a separate docket.

19. On February 14, 2002, the BCP filed a Motion to Strike ("BCP Motion to Strike") the Rebuttal Testimony of NPC witness Mr. Ruelle in Docket No. 01-10001. Also on February 14, 2002, NPC filed its Response to the BCP Motion to Strike. At the Hearing on February 14, 2002, the Commission granted in part and denied in part the BCP Motion to Strike. (Transcript ("Tr.") at p. 1185, l. 14 through p. 1190, l. 18.)

20. Closing briefs regarding revenue requirements issues were filed on February 25, 2002 by NPC, NCCEU, BCP, and Staff in both dockets. Closing briefs regarding revenue requirements issues were filed on February 25, 2002 by USAN and MGM in Docket No. 01-10001.

21. On February 28, 2002, Clark County School District filed Comments in Docket No. 01-10001.

II. Cost of Capital

A. Capital Structure

NPC's Position

22. Through Richard Atkinson, NPC proposed the following capital structure on Certification (Exhibit 4 at p. 10.):

Description	Amount	Cap. Ratio %	Cost %
Short-term Debt	$ 200,000,000	6.53	7.22
Customer Deposits	$ 14,547,000	0.48	3.52
Long-term Debt	$1,348,835,000	44.04	6.94
Preferred Equity	$ 194,713,000	6.36	8.39
Common Equity	$1,304,354,000	42.59	12.25

Staff's Position

23. Staff witness Ronald Knecht recommended that the Commission adopt NPC's proposed structure (excluding the Cost of Common Equity), including the associated Short- and Long-Term Debt Cost elements. (Exhibit 7 at p. 2.) However, Mr. Knecht recommended that the Cost of Customer Deposits be set at 1.765 percent, which is the rate set in a posting by the Commission Secretary on December 6, 2001. (Id. at 2.)

BCP's Position

24. David Parcell, witness for the BCP, recommended the same capital structure and cost elements proposed by NPC, excluding the Cost of Common Equity. (Exhibit 15 at p. 3.)

SNWA's Position

25. Dr. Dennis Peseau, witness for SNWA, proposed a capital structure consisting of 40 percent Common Equity, 6.5 percent Preferred Equity, and 53.5 percent Debt. (Exhibit 14 at p. 3.) Dr. Peseau argued that the proposed amount of Common Equity, 42.59 percent, does not represent a normal or actual structure for the NPC. (Id. at 22.)

26. Dr. Peseau cited two reasons for his recommendation: NPC and its parent, Sierra Pacific Resources ("SPR"), regularly transfer equity between each other; and NPC is proposing a $258 million off-balance sheet debt financing through a contract price adjustment. (Id.) Dr. Peseau indicated that the contract price adjustment, in the range of $258 million, would effectively lower the percent of Common Equity. (Id. at 24.) This price adjustment, together with the regular transfers of equity between parent and subsidiary, justify his recommended capital structure. (Id.)

27. Dr. Peseau also raised the issue of how to account for Deferred Federal Income Tax ("DFIT"), relating to the $922 million in NPC's Deferred Energy Account. According to Dr. Peseau, there is $325 million in DFIT associated with the Deferred Energy Balance. (Exhibit 14 at p. 25.) Dr. Peseau believes that the DFIT represents zero cost capital and should be addressed by adding $325 million to the capital structure at zero cost or offsetting the total Deferred Energy Balance used to compute carrying charges. (Id. at 26.) The SNWA takes no position, through Dr. Peseau's testimony, as to whether this should be part of the General Rate Case (Docket No. 01-10001) or the Deferred Energy Case (Docket No. 01-11029). (Id.)

MGM's Position

28. John Thornton, witness for MGM, recommended that DFIT that has not been recorded by NPC as an offset to rate base, be used in the capital structure as a cost-free source of funds. (Exhibit 11 at p. 45.) Mr. Thornton's proposed adjustments to the capital structure include a small correction, as well as the addition of the DFIT at zero cost. (Id. at 45-46.) His recommendation incorporates the same cost amounts that NPC recommended, excluding Cost of Common Equity, and results in the following weights: (Exhibit 11 at JST-1, p. 24.)

Short-term Debt	6.30 %
Customer Deposits	0.46 %
Long-term Debt	42.49 %
Deferred Tax (0 % cost)	3.54 %
Preferred Equity	6.13 %
Common Equity	41.08 %

NPC's Rebuttal Position

29. NPC witnesses Deborah Florence and Patricia Franklin provided rebuttal testimony related to the issues of DFIT in rate base and DFIT resulting from deferred energy accounting. According to Ms. Franklin and Ms. Florence, items not generated by or associated with rate base, were excluded from rate base in accordance with NAC 704.6526. (Exhibit 22 at p. 2, Exhibit 23 at p. 2.)

30. Ms. Florence further explained that deferred taxes resulting from the deferral of fuel and purchased power do not represent zero cost capital, or any source of capital, because NPC will not realize any tax savings in 2001. (Exhibit 23 at p. 3.) Ms. Florence emphasized that implementation of the deduction related to deferred energy does not provide cash in 2001, and that the tax benefit associated with the DFIT "will only be realized at some time in the future, when and as Nevada Power Company receives revenue to recover the deferred fuel balances through rates." (Exhibit 23 at p. 3-4.)

31. Ms. Franklin suggested that the treatment of DFIT created by deferred energy accounting in the General Rate Case, and the Deferred Energy Balance in the Deferred Energy Case, created a permanent mismatch between the asset and the tax that is generated or associated with the asset. Further, she stated, in view of the provisions of NAC 704.150, it makes more sense to address the deferred tax balances associated with the Deferred Energy Balance through the deferred energy accounting mechanism. (Exhibit 22 at p. 4.)

32. Richard Atkinson also provided rebuttal for NPC. Mr. Atkinson indicated that Mr. Thornton's proposal to add deferred taxes associated with non rate base items to the capital structure, as a zero cost item, is inappropriate. Mr. Atkinson pointed out that no cost free capital exists if total assets match the asset base, and he indicates that, in NPC's case, this is true. (Exhibit 16 at p. 5.)

33. Mr. Atkinson further stated that Dr. Peseau's lowering of the Common Equity Ratio is arbitrary and not justified. (Exhibit 16 at p. 8.) Mr. Atkinson also disagreed with Dr. Peseau regarding the existence of $325 million of zero cost capital in DFIT associated with the Deferred Energy Balance. (Id. at 8.)

Commission Discussion and Findings

34. The Parties in this phase of the proceeding generally agree with NPC's proposed capital structure. Differences occur in two areas: 1) the treatment of DFIT, as proposed by Dr. Peseau and Mr. Thornton; and 2) Dr. Peseau's proposed treatment of off-balance sheet financing together with equity transfers between parent and subsidiary.

35. The Commission is aware that transfers of equity between parent and subsidiary occur on a regular basis. However, the status of the capital structure at the end of the Test Period, updated through the Certification Period, must be based on actual recorded numbers. Dr. Peseau recommends that the Commission look back a couple of months and take into account "things that we know right now in terms of the PIES (Premium Income Equity Securities) equity issuance and the proposed contract price adjustment mechanism…." (Tr. at p. 227-228.) This implies that the Commission should make "guesstimates" based on possible changes in financing arrangements or other areas affecting the capital structure. Such an approach would be contrary to our regulations and set the precedent for arbitrary adjustments.

36. Mr. Thornton recommends using certain non rate base related DFIT as a source of cost free capital. Dr. Peseau recommends using DFIT associated with the Deferred Energy Balance as either: 1) a source of cost free capital; or 2) as a reduction to the Deferred Energy Balance used to calculate the carrying charge. The Commission agrees with NPC that items not generated by or associated with rate base should be excluded from rate base. Although the Commission does not agree with Ms. Florence regarding the timing of tax benefits, we do agree with Ms. Franklin that the issue of DFIT relating to the Deferred Energy Balance is more appropriately considered in the context of the Deferred Energy Case.

37. Mr. Knecht recommended using the most recent Customer Deposit rate set by the Commission, 1.765 percent. Since this a known and measurable quantity which will be in effect when the new rates go into effect, and NPC is requesting rate base treatment for the Customer Information System that came on line subsequent to the Certification Period, this is a reasonable adjustment.

38. Accordingly, the Commission finds that the capital structure proposed by NPC, adjusted for the cost of Customer Deposits at 1.765 percent and excluding the Cost of Common Equity, is appropriate, to wit:

Description	Amount	Cap. Ratio %	Cost %
Short-term Debt	$ 200,000,000	6.53	7.22
Customer Dep.	$ 14,547,000	0.48	1.765
Long-term Debt	$1,348,835,000	44.04	6.94
Preferred Equity	$ 194,713,000	6.36	8.39
Common Equity	$1,304,354,000	42.59	

B. Return on Common Equity

Introduction

39. In establishing rates that are just and reasonable, the Commission must first establish an appropriate level of return on Common Equity that allows NPC to earn a fair return. The concept of a fair return has been enunciated in a number of well-known cases, such as Hope[2] and Bluefield[3]. This return, or interest rate, is a major input into the weighted Cost of Capital; which is the overall rate of return on rate base used to establish the revenue requirement for NPC. In developing the appropriate rate of return, the Commission relies on witnesses who are experts in the field of finance to provide reasonable estimates of what the rate of return should be. These experts utilize well-known mathematical models, such as the Discounted Cash Flow, Capital Asset Pricing Model and Risk Premium methods, together with their professional judgment, to estimate what rate of return is required to allow NPC to earn a fair return.

---

[2] F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).
[3] Bluefield Waterworks and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).

NPC's Position

40. Roger Morin, witness for NPC, recommended a return on Common Equity of 12.5 percent. Dr. Morin arrived at his recommendation through studies utilizing the Capital Asset Pricing Model ("CAPM"), Risk Premium method, and the Discounted Cash Flow ("DCF") method. Further, Dr. Morin's proposed return is based, in part, on his estimate that NPC's risk environment exceeds the industry average due to a deterioration in NPC's financial profile. (Exhibit 3 at p. 4.) To quantify this, Dr. Morin added 40 basis points to his required return. (Id. at 28-29 and 39-40.)

41. Dr. Morin's recommendation reflects the application of his professional judgment of NPC's risk environment, the need to strengthen NPC's credit standing, and the results of his analyses. (Id. at 5.) Dr. Morin's analyses included two CAPM studies, three Risk Premium studies, and DCF analyses of three surrogates for NPC. (Id.) However, in utilizing these various methods, Dr. Morin recognized that no single method provides sufficient precision, or accuracy, for it to be relied on by itself to estimate a fair return. (Id. at 14.) Also, in Dr. Morin's estimate, the current fast-changing environment makes it difficult to implement traditional methodologies. (Id. at 15.)

42. In his CAPM method, Dr. Morin used as a proxy for the risk-free rate the long-term yield on U.S. Treasury Bonds of 5.5 percent, rather than the short-term rates, which he considered too volatile. (Id. at 17-18.) Dr. Morin's beta of 0.70 was developed from betas for natural gas companies and oil and gas producers. (Id. at 19-21.) Dr. Morin's market risk premium of 7.5 percent was estimated from Ibbotson Associates and a DCF analysis of the aggregate equity market. (Id. at 24-25.) In developing the market risk premium, Dr. Morin determined that the best estimate of the future risk premium is the historical mean. (Id. at 25.) The result of this analysis is a value of 10.8 percent. (Id. at 27.) Dr. Morin's empirical version of the CAPM resulted in a value of 11.3 percent. (Id.) Three other risk premium methods used by Dr. Morin resulted in a range of 11.3 to 12.0 percent. (Id. at 28-35.)

43. In the DCF analyses, Dr. Morin used three proxy groups for NPC: 1) Moody's[4] electric utilities; 2) a group of vertically integrated electric utilities; and 3) a group consisting of widely-traded dividend-paying natural gas distribution companies from Value Line's Gas Distribution Group. (Id. at 36-37.) Dr. Morin used the spot dividend yields in the August 2001 edition of Value Line Investment Survey ("VLIS"). (Id. at 38.) Earnings growth estimates

[4] As referred to in Moody's Public Utility Manual.

developed by professional analysts employed by large investment brokerage institutions were used as a proxy for expected dividend growth. (Id.)

44. Using Institutional Brokers' Estimate System's ("IBES") estimates for long-term growth, Dr. Morin obtained an estimate of 12.1 percent. He adjusted this by 40 basis points for greater risk to 12.5 percent, excluding a floatation cost adjustment. Using VLIS's long-term growth forecast, he obtained a value of 12.7 percent, with a 40-basis point risk adjustment and excluding floatation costs, this value increased to a 13.1 percent estimate for the required rate of return. (Id. at 39-40.)

45. Dr. Morin conducted a similar analysis on Moody's "Vertically Integrated Electric Utilities". The IBES estimate of long-term growth resulted in a value of 12.6 percent, and the VLIS estimate of long-term growth resulted in a value of 13.6 percent, excluding floatation costs for both estimates. (Id. at 40-41.)

46. Utilizing the Gas Distribution Utility Industry ("LDC") as a proxy for a significant proportion of NPC's electric utility business, Dr. Morin conducted DCF analyses with IBES and VLIS estimates of long-term growth. (Id. at 41-42.) Excluding floatation costs, his results were estimates of 12.5 and 16.1, respectively, for the required rate of return. (Id. at 42.)

47. In summary, Dr. Morin noted that the average of the various tests was 12.6 percent, with a median of 12.5 percent, including floatation costs. If the outlying value of 16.1 percent is ignored, the resulting range is 11.1 to 13.9 percent, with a midpoint of 12.5 percent (including floatation costs adjustment). Accordingly, Dr. Morin recommends 12.5 percent as a just and reasonable return on Common Equity. Without a floatation costs adjustment of 0.3 percent, this becomes 12.2 percent. (Id. at 48-49.)

48. Mr. Atkinson, witness for NPC, indicated on rebuttal that Dr. Morin's recommendation of 12.5 percent had been adjusted downward by 25-basis points in order to account for the regulatory treatment of Common Equity issuance expense. (Exhibit 16 at p. 10.) Therefore, NPC's requested return on equity is 12.25 percent. (Id.)

Staff's Position

49. Mr. Knecht, witness for Staff, recommended that the Commission adopt a return on Common Equity of 10.0 percent, and not allow a floatation costs premium since the amortization of actual costs is already allowed. (Exhibit 7 at p.1-2.) Mr. Knecht also recommended that the Commission adopt as reasonable a range of 9.6 to 10.2 percent, noting that Staff's recommendation is in the upper part of the recommended range. (Id. at 2.) Mr.

Knecht identified the following methods Staff used to establish a reasonable return on Common Equity: 1) Comparable Earnings; 2) DCF; 3) CAPM; 4) other Risk Premium models; and 5) Market-to-Book ("M/B"). (Id. at 2-3.) Mr. Knecht stated that each approach has merit in principle; however, all but certain DCF methods have "debilitating implementation problems". (Id. at 3.) According to Mr. Knecht, Staff relied on three-stage DCF models for its return on equity calculations. (Id.)

50. Mr. Knecht indicated that Staff's estimates are based on the "entire universe of 84 electric-utility, natural gas local distribution company and combination energy-utility firms", including SPR. (Id. at 3) Mr. Knecht believes that no one has demonstrated a basis for concluding some firms are more similar to NPC than others. (Id.) Mr. Knecht noted that Staff's results in this case are the lowest he has found in over 12-years experience of return on equity estimates. (Id. at 4.)

51. In reviewing NPC's analyses, Mr. Knecht noted a number of deficiencies. With regard to the DCF analysis, according to Mr. Knecht, Dr. Morin utilized sources known to be biased toward high growth-rate forecasts and with the poorest track records. (Id. at 5.) Mr. Knecht also noted that a single-stage DCF model, such as that used by NPC, apply the initial growth rates infinitely into the future. To avoid the distortion caused by a single-stage growth estimate, two- and three-stage models moderate the initial estimate of the growth rate in subsequent periods to allow for a more sustainable rate. (Id.)

52. Mr. Knecht noted that the CAPM, market risk premium ("MRP"), and other Risk Premium models have a number of problems. The problems include artificial adjustments to the beta in CAPM, inflation of the MRP results due to the use of a spot intermediate-term earnings growth forecast, and inflation of the results of the other Risk Premium models. (Id. at 6-7.) The inflation of the other Risk Premium models results from failure to use long-term government bond returns, the addition of 40 basis points due to lower bond ratings, and failure to use an actual market based estimate. (Id. at 7.) One final caution, Mr. Knecht noted, is that use of historic data may tend to bias the results to the upside when risk premiums may be falling, and vice versa. (Id. at 8.) The way historic data is used in DCF models avoids this problem. (Id.)

53. In Staff's DCF model, Mr. Knecht utilized all 84 energy utilities for which data was reasonably available. (Id. at 11.) For the dividend growth rate estimate, Mr. Knecht used VLIS data, adjusted for the actual time period in question. (Id.) Mr. Knecht also estimated the growth rate using the retention-ratio method, computed from the actual returns on equity,

earnings, and dividends available over the longest period for which complete data was available. (Id. at 12.) The result was a mean rate of return of 9.85 percent. (Id. at 13, Attachments ("Atch") RLK-3 at p. 1-2, RLK-4 at p. 1-2.) This return was then adjusted by one-eighth of a year's return to account for a difference in time between discounted dividends and prices. The adjustment results in the addition of 0.12 percent, increasing the final rate of return to 9.97 percent, rounded to 10.0 percent. (Exhibit 7 at p.14.)

54. According to Staff, the estimated return on Common Equity of 10.0 percent is related to a Common Equity percentage of 43.11. In order to account for the difference between this and the Staff requested amount of 42.59 percent, the 10.0 percent must be adjusted further depending on how Preferred Stock is treated. The final result is a range between 9.6 and 10.2 percent. (Id. at 15.)

55. Staff also estimated the return on Common Equity using the CAPM model. In doing so, Staff used an average of the yield of the 30-year U.S. Treasury Bond and the 10-year U.S. Treasury Note for the risk free rate. (Id. at 22.) Mr. Knecht used raw beta values from *Standard & Poor's Stock Reports*[5] and the Ibbotson Associates method to compute the market risk premium. (Id.) Mr. Knecht reported the results as a range between 5.87 and 6.31 percent; and therefore, concluded that the results using the CAPM are probably biased toward low values and are unreliable. (Id. at 23.) Mr. Knecht accounted for this bias as problems relating to: the way the market risk premium is calculated and the measurement of the beta. (Id. at 25.) The market risk premium relies on historical data that may not reflect current risk assessments by the market. The beta is assumed to be highly correlated between changes in an individual stock and the market index, but it actually has a low correlation. (Id.) Mr. Knecht believes attempts to adjust the beta result in the application of a factor, without analytical justification to another factor, with only a weak correlation to the statistic being measured. (Id. at 26.)

56. Mr. Knecht also calculated the return on Common Equity using the same method as Dr. Morin for Dr. Morin's first two non-CAPM Risk Premium methods (Capital Appreciation plus Income or "CA+I"), but corrected two errors and updated the results. (Id. at 29.) According to Staff, Dr. Morin, as a result of the errors, inflated the riskless rates by 50 basis points in each case. The result reduces Dr. Morin's CA+I result for the electric-index return on equity from 11.5 to 10.51 percent and the gas-LDC-index return on equity from 12.0 to 10.6 percent. These

---

[5] June and September 2001 issues.

corrections, together with the updates, result in returns on equity of 10.18 (electric) and 10.22 (gas) percent, which are within Staff's recommended range. (Id. at 31, Atch RLK-11 at p. 1-2.)

57. In conclusion, Staff calculated a Pre-Tax Interest Coverage Ratio based on Staff's recommended capital structure and return on Common Equity. The computation indicates that the Ratio will be about three times Interest Charges. According to Staff, this Ratio will be in a range that will help NPC maintain its creditworthiness. (Id. at 36, Atch RLK-12 at p. 2.)

USAN's Position

58. Dr. Martin Blake, witness for the USAN, provided testimony "to demonstrate that the electric industry is currently riskier than it has been", and to recommend that a return on equity at the high end of the range, as proposed by Dr. Morin, is reasonable. (Exhibit 10 at p. 6.) Dr. Blake identified a number of factors that would justify a higher return on investment, including: a change in the regulatory model, an increase in volatility in the wholesale market, increased bankruptcies in the electric industry, potential competition, defaults on purchased power contracts, and cost recovery issues related to Regional Transmission Organizations ("RTOs"). (Id. at 8.) Additionally, Dr. Blake argued that NPC shareholders currently under-earn on NPC's rate base relative to the fair market value of these assets. (Id. at 24.) In conclusion, Dr. Blake recommended a rate of return toward the top of the range identified by Dr. Morin to account for the fact that the rate base used in ratemaking is below the fair market value of those assets. (Id. at 25.)

MGM's Position

59. John Thornton, for MGM, provided testimony arguing that Dr. Morin's methods are inappropriate and that his results are biased upwards. (Exhibit 11 at p. 2.) Mr. Thornton argued that current capital costs are low compared to historical capital costs, based on the decline in 5-, 7-, and 10-year U.S. Treasury Rates since 1981. (Id. at 4.) Mr. Thornton also stated that using a geometric average of returns, a return above 11 percent would exceed all of his index series returns. (Id. at 6.) Further, Mr. Thornton indicated that electric utilities are significantly less risky than the average risk security, based on a CAPM beta of 1.0 for average risk securities and a beta of 0.54 for his sample of electric utilities. (Id. at 12.)

60. In conducting his analyses to estimate NPC's cost of equity, Mr. Thornton used the DCF and CAPM models with Dr. Morin's sample of companies. (Id. at 12-13.) Like Staff, Mr. Thornton used a multi-stage DCF growth model incorporating VLIS dividend growth estimates. (Id. at 15.) Mr. Thornton's sample's average dividend yield is 4.84 percent for the

next twelve months, with 3 to 4 percent for the final stage. (Id. at 15-16.) As a result, Mr. Thornton estimated a range of 8.5 to 9.3 percent, with a midpoint of 8.9 percent for the return on equity. (Id. at 17.)

61. In Mr. Thornton's CAPM model, he used 4.7 percent for the risk-free rate, which is an average of intermediate-term U.S. Treasury securities. (Id. at 21-22.) For his beta, Mr. Thornton used 0.54, which is an average VLIS beta for his sample companies. (Id. at 23-24.) Mr. Thornton used a range for his market risk premium representing the highest and lowest estimates from his estimation procedure. (Id. at 23.) The estimation procedure was a three-step process involving: index returns; intermediate-term U.S. Treasury securities; and the difference between holding a stratified portfolio and holding the risk-free rate over the intermediate term. (Id. at 24-25.) The result was a range of 6.20 to 6.60 percent for market risk premium. (Id. at 25.) Based on the foregoing inputs, Mr. Thornton estimated the return on equity in the range 8.0 to 8.6 percent. (Id. at 27-28.) Additionally, Mr. Thornton stated, that based on his study of the monthly sample average betas of 74 electric utilities since the mid to late 1970s, the risk of integrated electric utilities has fallen since 1997 relative to the market in general. (Id. at 28.)

62. In conclusion, Mr. Thornton recommended a range from 8.0 to 9.3 percent, with 8.6 percent as the most appropriate return on equity. (Id. at 29.)

63. Mr. Thornton also noted a number of problems associated with Dr. Morin's analyses. According to Mr. Thornton, Dr. Morin's choice of the risk-free rate in his CAPM model was not appropriate for a number of reasons, including the fact that he did not match the expected holding period to the term of the U.S. Treasury securities. Other factors observed by MGM relating to the use of the long-term U.S. Treasury securities by Dr. Morin included the fact that the use of this security was not observed in any academic study and that the 30-year bond has a "liquidity risk premium" built into it. (Id. at 30-32.)

64. Mr. Thornton also found fault with Dr. Morin's beta estimate. Dr. Morin's beta was constructed from three separate industries outside the electric industry, which is inappropriate. (Id. at 33.) Mr. Thornton also criticized Dr. Morin's market risk premium calculation as being biased upward because Dr. Morin implicitly chose a one-month holding period, while his CAPM application assumes a long-term holding period (i.e., long-term U. S. Treasuries used for the risk-free rate). (Id. at 34.) With regard to Dr. Morin's empirical CAPM model, Mr. Thornton believes that Dr. Morin has not demonstrated that the results could be

applied to any CAPM model that uses long-term U.S. Treasury Bond yields for the risk-free rate. (Id.)

65. With regard to Dr. Morin's DCF model, Mr. Thornton disagreed with the use of near-term earnings growth forecasts to model infinite dividend growth. Rather than relying on direct forecasts of dividend growth, Dr. Morin used upwardly biased earnings growth rates. (Id. at 37-40.)

SNWA's Position

66. Dr. Peseau, witness for SNWA, testified that a fair and reasonable return on equity for NPC is 10.5 percent. (Exhibit 14 at p. 3.) Dr. Peseau did not develop an independent analysis, but chose to examine Dr. Morin's analysis. (Id. at 4.) According to Dr. Peseau, Dr. Morin utilized three principal assumptions that led to an exaggerated return on equity. (Id. at 5.) The faulty assumptions are: 1) Dr. Morin's sample companies under-represent the risks in the electric utility industry; 2) Dr. Morin's estimate of dividend growth rates are higher than the rates expected by investors and analysts, since they are based on growth in earnings per share rather than slower near term dividend growth; and 3) the beta in Dr. Morin's CAPM and empirical approximation of the CAPM ("ECAPM") models is too high. (Id. at 5-6.)

67. In Dr. Peseau's review of Dr. Morin's DCF model, he revised Dr. Morin's estimates by limiting sample companies to those that had at least 70 percent of their revenues from electric operations and making allowances for slower near-term dividend growth rather than faster earnings growth. (Id. at 6-7.) Dr. Peseau concluded that the appropriate range for the rate of return based on the DCF model was 10.3 to 11.0 percent. (Id. at 8.)

68. Dr. Peseau reported concerns with Dr. Morin's CAPM approaches in that both the beta and the market risk premium were too high. Dr. Peseau also adjusted the proxy Dr. Morin used for the risk-free rate, the 30-year U.S. Treasury Bond. (Id. at 15-18.) With his revisions and updates, Dr. Peseau developed an estimate of 9.5 percent (ECAPM) and 10.4 percent (CAPM) for the appropriate rate of return. (Id. at 18.)

69. Dr. Peseau also revised Dr. Morin's Risk Premium model. Based on a new estimate of the risk-free rate, 5.4 percent, and Dr. Morin's regression results, Dr. Peseau calculated a rate of return of 10.8 percent. (Id. at 20.)

70. Based on the foregoing, Dr. Peseau concluded that a rate of return on Common Equity of 10.5 percent was fair and reasonable. (Id. at 20.)

BCP's Position

71. David Parcell, witness for the BCP, utilized the DCF, CAPM and Comparable Earnings models to estimate the appropriate rate of return for NPC. In the DCF model, Mr. Parcell concluded that the dividend growth component was the most crucial and controversial element. (Exhibit 15 at p. 23.) Mr. Parcell observed that no single indicator of dividend growth was used by all investors. Consequently, he considered several indicators of growth. These indicators included a five-year average for earnings retention, earnings per share, dividends per share and book value per share. He also considered projections of earnings retention growth, earnings per share, dividends per share, and book value per share. Finally, he considered five-year earnings projections from *First Call* (or IBES). (Id. at 23.) Based on calculations for his comparison groups, Mr. Parcell developed a range of 10.4 to 11.0 percent for a reasonable rate of return using his DCF model. (Id. at 24.)

72. Mr. Parcell also estimated the rate of return using the CAPM model. Mr. Parcell believes that the CAPM model is generally superior to a simple Risk Premium model because the CAPM recognizes the risk of a particular company or industry. (Id. at 25.) Mr. Parcell performed his analysis using the same companies he used for the DCF analysis. Using those companies and a three-month average yield of 30-year U.S. Treasury bonds for the risk-free rate, he identified the rate of return as 5.31 percent. (Id. at 25-26.) Mr. Parcell used the most recent VLIS betas for each company. Mr. Parcell developed a market risk premium utilizing the return on equity for the Standard & Poor's ("S&P") 400 Industrials dating back to 1949. (Id. at 27.) He also considered the S&P 500[6]. Combining the results from both, Mr. Parcell estimated the market risk premium at 13.5 percent. (Id.) The results indicate a range of 9.7 to 10.0 percent for the comparison groups, and a rate of 11.5 percent for SPR. Based on these CAPM results, Mr. Parcell concluded that a range of 9.75 to 10.0 percent for the return on equity was appropriate. (Id. at 27-28.)

73. Mr. Parcell also conducted an analysis of the rate of return using the Comparable Earnings methodology. This methodology is designed to measure the returns expected to be earned on the original cost book value of companies with similar risk. (Id. at 29.) Mr. Parcell examined realized returns on equity for several groups of companies in relationship to their market-to-book ratios. (Id.) Mr. Parcell reviewed the period 1992 to 2001, since the method requires a relatively long period of time to develop the desired relationship. (Id. at 30.) Based

---

[6] Standard & Poor's Analyst's Handbook 2001.

on this methodology, Mr. Parcell estimated the range of 11.3 to 14.2 percent return on equity for his comparison groups, and 9.5 to 10.0 percent for SPR. (Id.) Mr. Parcell noted that this study indicates that the Cost of Common Equity has declined over recent years and that an earned return of 11 percent or less should result in a M/B ratio of at least 100 percent. (Id. at 32.)

74. In conclusion, Mr. Parcell recommended a range of 9.75 to 11.0 percent for the Cost of Common Equity, with the midpoint of 10.375 percent as the appropriate return on equity for NPC. (Id. at 33.)

75. Mr. Parcell also indicated that he had a number of concerns with Dr. Morin's testimony. According to Mr. Parcell, the primary concern is with Dr. Morin's use of hypothetical betas. Mr. Parcell believes that none of Dr. Morin's selected groups, which include gas distribution companies, gas pipeline companies, and oil and gas producers, presents a reliable proxy for NPC, an electric company. (Id. at 37.) Had Dr. Morin used proper betas, the results would have been a range of 9.25 to 10.15 percent. (Id. at 38.)

76. Additionally, with regard to Dr. Morin's ECAPM analysis, Mr. Parcell indicated that it overstated the cost of equity by inflating the cost of one-fourth of the equity. (Id. at 39.) With regard to Dr. Morin's Risk Premium model, Mr. Parcell stated that it was merely an examination of historical events that assumes that remote events would have the same influence at the current time. (Id. at 40.) Mr. Parcell also took exception with Dr. Morin's analysis where Dr. Morin took an average risk premium over the 1931 to 2000 period, and applied it to the current level of U.S. Treasury Bond yields. (Id. at 41.) Mr. Parcell suggested that had Dr. Morin been consistent with the use of his historic risk premium in applying the allowed returns risk premium, the result would have been a return of 10.1 percent. (Id. at 41.)

77. Finally, Mr. Parcell identified a major problem with Dr. Morin's DCF model. According to Mr. Parcell, Dr. Morin erred when he used only one indicator of growth, namely, earnings per share growth. (Id. at 42.) Mr. Parcell noted that the DCF model is a "cash flow" model, and the cash flow is dividends. In this regard, Dr. Morin's model does not even consider dividend growth rates. (Id.)

NPC's Rebuttal Position

78. Dr. Morin provided rebuttal testimony for NPC. According to Dr. Morin, Mr. Thornton's recommendation is outside the mainstream of both financial theory and practice. (Exhibit 17 at p. 4.) Dr. Morin specifically rejected Mr. Thornton's use of historical growth data as redundant, particularly because his stock price estimate was predicated on forecasted growth.

(Id. at 5.) Dr. Morin maintained that Mr. Thornton should have used earnings growth rather than dividend growth, since dividends are going down. (Id.) Dr. Morin also criticized Mr. Thornton's CAPM analysis for: the use of intermediate-term bond yields; a beta that is downward biased; and a market risk premium that is too low because both a geometric mean and arithmetic mean were used as a factor, instead of only an arithmetic mean. (Id.) Dr. Morin stated that Mr. Thornton's return on equity recommendation of only 8.6 percent implies a risk premium of only 3 percent, which is inconsistent with the finance literature and the actions of regulatory commissions in the last decade. (Id. at 27.)

79. Dr. Morin also took exception with Dr. Peseau's analyses. According to Dr. Morin, Dr. Peseau was able to produce a lower return on equity value in the DCF analysis by eliminating two companies and substituting near-term growth for long-term earnings growth in dividends. (Id. at 35.) Dr. Morin also disputed Dr. Peseau's modifications to the CAPM model, explaining why disregarding historical betas was appropriate. (Id. at 38.) Dr. Morin also reported that Dr. Peseau's modifications of Dr. Morin's risk premium were incorrect. (Id. at 39.)

80. Dr. Morin stated that Mr. Knecht's analysis was too narrow in scope and that he placed "all his eggs in the DCF basket". (Id. at 43.) Dr. Morin believes that Mr. Knecht failed to recognize any risk differences between NPC and the entire population of energy utilities. (Id.) Dr. Morin also believed that Staff should have focused on the higher risk segment of the sample. (Id. at 45.) Dr. Morin criticized Mr. Knecht's choice of dividend growth rates and reiterated his position that earnings growth forecasts should be used in the DCF model. (Id. at 47.) Further, Dr. Morin suggested that Mr. Knecht's use of the retention growth method in the second stage of the DCF model had fundamental problems. (Id. at 48.) Dr. Morin identified a downward bias of 30 to 40 basis points due to these errors. (Id. at 50-51.)

81. Dr. Morin further defended his use of earnings growth forecasts, rather than the dividend growth forecasts used by Mr. Knecht, by noting that empirical research and common sense indicate that investors rely on analysts' growth rate forecasts. Dr. Morin also asserted that the paucity of dividend forecasts produces unreliable results and believes that Mr. Knecht's third stage growth rate of 5.5 percent is too low. (Id. at 53-54.) With regard to Mr. Knecht's CAPM model, Dr. Morin also disagreed with Mr. Knecht's assertion that Ibbotson Associates relies on raw betas. (Id. at 54.)

82. With regard to Mr. Parcell, Dr. Morin stated that the yield component in Mr. Parcell's DCF model was downward-biased. (Id. at 56.) Dr. Morin restated his objections to the

use of the retention growth method as applied by Mr. Parcell, and criticized Mr. Parcell's use of historical growth rates. (Id. at 58-59.) Dr. Morin criticized Mr. Parcell's Comparable Earnings approach because the results for his comparable groups all exceed Mr. Parcell's recommended return on equity and because M/B ratios are largely irrelevant. (Id. at 62.)

Commission Discussion and Findings

83. The Parties in this phase of the proceeding have utilized the traditional tools required to develop the appropriate return on equity. All of the witnesses are highly regarded experts in the field of finance, and this Commission appreciates their testimony.

84. In the instant case, the Commission is presented with a range of rates from 8.0 to 12.25 percent. The range was developed using the appropriate tools, adapted to this case based on each professional's personal judgment.

85. Dr. Morin examined the state of the environment for NPC and concluded that the current risk environment exceeded the industry average due to deterioration in NPC's financial profile. Based on his experience, Dr. Morin quantified this extra risk by adding 40 basis points to his required return. This estimate, together with his analyses, led Dr. Morin to conclude that the appropriate rate of return should be 12.5 percent, reduced to 12.25 percent by Mr. Atkinson, due to the flotation cost adjustment.

86. In Dr. Morin's conclusion, he used the average of his various tests to develop a range and a specific recommendation. In making his recommendation, Dr. Morin has applied equal weight to each of his tests.

87. Mr. Knecht based his recommendation of 10.0 percent primarily on the results of his DCF analysis, after noting a number of problems with the other tests. Mr. Knecht also utilized a refined version of the DCF model, and incorporated all relevant energy utilities to arrive at his recommendation. Dr. Blake supported Dr. Morin's analysis and recommended that the allowed rate of return be at the upper end of Dr. Morin's results. Mr. Thornton replicated Dr. Morin's analyses with much lower results. His recommendation is a rate of return of 8.6 percent. Dr. Peseau and Mr. Parcell were very close to Staff's recommendation, with results of 10.5 and 10.375 percent, respectively.

88. Staff, MGM, SNWA, and BCP witnesses all noted a number of weaknesses with Dr. Morin's analyses. These weaknesses include the use of a single-stage DCF model and use of earnings growth estimates to approximate dividend growth. Weaknesses in the Risk Premium estimates were also noted. In using his CAPM, Dr. Morin, according to the referenced

witnesses, used inappropriate betas and Market Risk Premiums. Additionally, problems with Dr. Morin's risk-free rate were noted.

89. Dr. Morin noted several objections to other parties' use of their DCF and Risk Premium models. Dr. Morin's principal objections centered around their use of dividend growth rates in their DCF analyses and their use of lower betas in their CAPM models, both of which produced lower returns on equity. However, while investors might rely on earnings growth forecasts for some decisions, the DCF model specifically requires the use of dividend growth estimates.[7]

90. Dr. Morin also criticized the use of the entire set of energy utilities by Mr. Knecht, yet Dr. Morin only used gas and oil companies for his comparison companies in his CAPM mode. The Commission believes Mr. Knecht's use of the entire set is no less valid than Dr. Morin's use of non-electric utilities.

91. Dr. Morin criticized a downward bias of as much as 40 basis points in Mr. Knecht's DCF model, yet Dr. Morin arbitrarily added 40 basis points as a risk adjustment. Again, the Commission believes that Mr. Knecht's estimate is no less valid than Dr. Morin's adjustment.

92. In the past, this Commission has primarily relied on the DCF analysis, with various Risk Premium analyses used to check the reasonableness of the result. The Commission, based in large part on the testimony of Mr. Knecht, still believes that the DCF model, especially the three-stage model, provides the best estimate of the appropriate rate of return. The Commission concurs with Mr. Knecht that the DCF model avoids the problem of bias introduced by the way historic data is used in Risk Premium models. However, it is clear that Dr. Morin's DCF model suffers from the failure to use dividend growth estimates, rather than earnings growth estimates. Additionally, the Commission agrees with Mr. Knecht that, "…at this time little or no weight can reasonably be given to the ROEs (returns on equity) estimated by the CAPM and other RP (Risk Premium) (CA+I) models, even when they are implemented correctly." (Exhibit 7 at p. 8.) This view is supported by Dr. Morin's observation that the current fast-changing environment makes it difficult to implement the traditional methodologies.

93. In general, the Risk Premium models are still useful to provide support for the DCF results. However, the Commission notes that the CAPM model has a major deficiency; the experts disagree over the relevant proxy for the risk-free rate. Historically, there has been a

---

[7] See James C. VanHorne, Financial Management and Policy (Second Edition) at p. 94-95.

significant difference between short, intermediate, and long-term government bond yields, assuming a normal yield curve. In this case, Dr. Morin and Dr. Peseau used the long-term U.S. Treasury Bond yield for the risk-free rate, while Mr. Thornton used the intermediate-term yield. This difference alone, in a normal environment, could result in significant differences between experts.

94. In relying on the DCF model, the Commission considers the results of the Parties' DCF analyses. Dr. Morin obtained a range from 12.8 to 13.9 percent. Mr. Knecht developed a range from 9.6 to 10.2 percent. Mr. Thornton's range was 8.5 to 9.3 percent. Dr. Peseau reported a range from 10.3 to 11.0 percent, while Mr. Parcell's range was 10.4 to 11.0 percent. Given the problems with Dr. Morin's estimates enumerated by four of the parties, the Commission considers Dr. Morin's results to be outside of a reasonable range. Further, in light of Mr. Knecht's utilization of all 84 utilities for which data were reasonably available, the Commission believes that his analysis represents the best estimate of the appropriate return on equity for NPC.

95. As indicated, the other Risk Premium results will be used to check the reasonableness of this conclusion. Given that the ranges proposed by the Parties vary between a low of 8.0 and a high of 12.25 percent, the Commission concludes that Staff's recommendation of 10.0 percent closely approximates the mid-point of the recommendations.

96. Mr. Knecht recommended a slight adjustment to accommodate a deviation from a Common Equity percent of 43.11, the amount and direction of which is dependent on the treatment of Preferred Stock. Since Preferred Stock has attributes of both debt and equity, the Commission believes that the hybrid nature of Preferred Stock justifies leaving Staff's recommendation near the midpoint. Since the flotation cost is treated as an expense with a two-year amortization, no adjustment to the Cost of Common Equity will be made.

97. The Commission believes that 10.1 percent return on equity is appropriate for NPC and will allow NPC to earn a fair rate of return.

98. Accordingly, the Commission finds that a 10.1 percent return on equity is reasonable. Additionally, the Commission finds that a 10.1 percent return on equity, combined with the accepted capital structure, results in a rate of return of 8.37 percent.

//

//

//

III. Revenue Requirement

A. Mohave O & M[8] True-up

Staff's Position

99. Staff's witness, Fred Buck, recommended reducing the O & M expenses at the Mohave generation plant by $185,000. Mr. Buck claimed NPC included out-of-period expenses from May 2000 in the test period; the test year covers the period from June 1, 2000 to May 31, 2001. These expenses need to be removed because they were incurred in the previous test year. (Exhibit 51, Atch FCB-3.)

NPC's Position

100. NPC agreed with Staff's adjustment. (Exhibit 84 at p. 21-22.)

Commission Discussion and Findings

101. Based on NPC's agreement with Staff, the Commission finds Staff's Mohave adjustment appropriate and will remove $185,000 from NPC's revenue requirement.

B. Income Taxes True Up

Staff's Position

102. Staff's witness, Mr. Buck, recommended an interest synchronization adjustment based on Staff's capital structure and rate base. The adjustment synchronizes Staff's proposed rate base to Staff's proposed weighted costs of capital. (Exhibit 51 at p.7-9.)

NPC's Position

103. NPC had a similar adjustment, which synchronizes its rate base to its capital structure. (Exhibit 2 at Schedule I-20.)

Commission Discussion and Findings

104. The Commission finds that an interest synchronization adjustment is appropriate to synchronize the approved rate base to the approved weighted costs of capital. The actual calculation is based on the Commission's determination of the appropriate rate base.

C. Annualized Mill Tax Expense

Staff's Position

105. Staff's witness, Mr. Buck, recommended reducing the mill tax rate (which was 4.0 mills on September 30, 2001) to 3.0 mills because he claimed the 4.0 mill rate was over-stated. Mr. Buck also recommended reducing NPC's proposed annualized base general revenues, used with the mill rate to calculate the mill tax assessment, to $561,349,000, because

---

[8] The Commission understands O & M to mean "operation and maintenance".

NPC's proposed revenues included energy related revenues that would not be approved until the Deferred Energy Case. (Exhibit 51 at p. 11-13.)

106. On cross-examination by the attorney for USAN, Robert Crowell, Mr. Buck testified that when Staff calculated its mill tax assessment, using the 3.0 mill rate, its calculation was an exception to public utility law and to the Commission's regulations. (Tr. at p. 690-691.) Mr. Buck also testified that he used a different mill tax rate than the approved rate of 4.0 mills, which was in effect at September 30, 2001. (Tr. at p. 689.)

BCP's Position

107. BCP's witness, Michael Brosch, recommended using a three-year average of actual mill tax assessments equal to $3.7 million. This is $2,148,000 less than NPC's proposed adjustment. (Exhibit 66 at p. 121-127.) Mr. Brosch claimed that NPC's proposed normalized revenues, which included energy related revenues, and the mill tax rate used to calculate its mill tax assessment, did not reasonably represent the probable future tax assessment. He claimed that the statutory ceiling of 4.0 mills should be adjusted based on significant changes in operating revenues and/or changes in approved budget levels. (Exhibit 66 at p. 122-123.)

MGM's Position

108. MGM's witness, Mark Garrett, recommended using the mill tax expense of $1,848,000, which was incurred by NPC in 2000. He claimed that NPC's proposed mill tax expense was overstated, although he admitted the mill rate had not been established for the 2002 and 2003 time period. (Exhibit 63 at p. 52.)

NPC's Rebuttal Position

109. NPC's rebuttal witness, Ms. Franklin, testified that NPC calculated the mill tax expense based on known and measurable criteria in accordance with NAC 703.2461. She testified that on September 30, 2001, the known and measurable mill tax rate was 4.0 mills. She claimed that BCP's and MGM's proposed mill tax adjustments are not consistent with NAC 703.2461, because their adjustments rely on historic mill tax expense, not on the known and measurable mill tax rate. However, Ms. Franklin also recognized that, similar to Staff's recommendation, NPC's mill tax assessment should be adjusted consistent with the final revenue requirement approved by the Commission in this docket and the subsequent Deferred Energy Case. (Exhibit 81 at p. 2-3.)

110. On cross-examination by the BCP, Ms. Franklin testified that NPC made a commitment to pay the mill taxes assessed to it by the Legislature, based on the known and measurable mill rate of 4.0. (Tr. at p. 1106-1107.)

Commission Discussion and Findings

111. Based on undisputed evidence, the Commission finds that the mill tax rate in effect on September 30, 2001, the end of the Certification Period, was 4.0 mills. The Commission finds this to be the known and measurable rate for the proper determination of the mill tax assessment in this case. The actual calculation is based on the Commission's determination of the revenue requirement.

D. Uncollectible Expense

Staff's Position

112. Staff's witness, Mr. Buck, claimed that NPC's annualized uncollectible expense was based on revenue levels that have not been approved. However, there would be an opportunity to adjust the uncollectible expense when the Commission approved the revenue requirement in the instant docket and the Deferred Energy Case. Mr. Buck also proposed adjusting NPC's uncollectible expense down by $5,088,000, based on his calculated expense using NPC's uncollectible rate and Staff's revenue levels, which did not include the deferred energy revenues. (Exhibit 51 at p. 14-15 and Atch FCB-12.)

BCP's Position

113. BCP's witness, Mr. Brosch, testified that NPC followed the Commission's ratio approach in developing its annualized uncollectible expense. He also testified that, in his experience, most regulatory agencies prefer to rely on analyses of actual net write-offs in establishing revenue requirements, rather than the accrual entry ratios such as this Commission had approved in the past. (Exhibit 66 at p. 103-104.) Mr. Brosch's uncollectible expense proposal of $3,164,000 recognized an annualized level of expense based on a three-year average of net bad debt write-offs. (Id. at 103 and Schedule C-6.)

NPC's Rebuttal Position

114. NPC's rebuttal witness, John Brown, testified that the BCP's proposal reflected only a three-year average of historical information, which would not account for changes in customer revenue or known changes in economic conditions. He also testified that NPC's methodology, which had been approved by the Commission as the most appropriate means of

calculating uncollectible expense, was much more sensitive to changes in current conditions. (Exhibit 79 at p. 8.)

115. On cross-examination by the BCP, Mr. Brown testified that NPC's methodology was correct and that it matched expenses to revenues. He also stated that his uncollectible expense was based on the revenues filed by NPC in this case and the Deferred Energy Case, and that the final expense would be adjusted pending the results of both cases. (Tr. at p. 1108-1109.)

Commission Discussion and Findings

116. The Commission believes that the ratio methodology approach requested by NPC to calculate its uncollectible expense had been approved by the Commission in the past because it matches revenues to expenses and is much more sensitive to changes in economic conditions. Therefore, the Commission reaffirms and finds that the ratio methodology approach is the proper way to calculate the uncollectible expense. The actual calculation is based on the Commission's determination of the revenue requirement.

E. Accumulated Depreciation, Docket No. 99-4006

Staff's Position

117. Staff's witness, Mr. Buck, recommended the implementation of depreciation rates approved by the Commission in Docket No. 99-4006. Mr. Buck claimed that the Commission reaffirmed its decision to implement the depreciation rates in Docket 99-4006 in its Order on Reconsideration dated November 28, 2000, but that NPC failed to comply with the Order. (Exhibit 51 at p. 18.) The impact of Staff's adjustment to implement the depreciation rates was a $6,672,000 increase in accumulated depreciation. (Exhibit 91 at Atch HGT-3, p. 2.)

NPC's Rebuttal Position

118. NPC's rebuttal witness, Bruce Rice, testified that the Order on Reconsideration, in Docket No. 99-4006, at page 8, Paragraph 42, did not specifically direct NPC to implement the depreciation rates. (Exhibit 83 at p. 25.)

Commission Discussion and Findings

119. The Commission finds that the Order on Reconsideration in Docket 99-4006 dated November 28, 2000, at page 8, Paragraph 42, dealt specifically with not implementing new depreciation rates for generation plant so as to not violate the "earnings adjustment" provision of NRS 704.982 for the provider of last resort function. However, the Staff's adjustment herein, which deals with new depreciation rates on transmission, distribution and general plant, specifically does not deal with depreciation rates on generation plant. Therefore, the

Commission finds reasonable the new depreciation rates on transmission, distribution and general plant that were approved by the Commission in Docket No. 99-4006, and approves Staff's adjustment to increase accumulated depreciation by $6,672,000.

F. The Sale of Excess SO2[9] Allowances

NPC's Position

120. NPC's witness, Ken Diaz, proposed to amortize $11,738,000 of SO2 allowances into rates over the next six years, which would total $2,611,000 per year. He claimed his six-year proposal was based on prior Commission Orders in Docket Nos. 97-6008 and 97-7030. He also claimed that the six-year proposal reflected the period over which the allowances were sold. (Exhibit 37 at p. 4-6.)

121. On cross-examination by Staff, Mr. Diaz testified that he recommended a six-year amortization of the SO2 allowances into rates to be consistent with the matching principle. (Tr. at p. 523.)

Staff's Position

122. Staff's witness, Jeff Galloway, recommended that the Commission should utilize a three-year amortization of the SO2 allowances in order to provide rate stability for the ratepayers. He also recommended reversing NPC's amortization of SO2 allowances in previous years, which would decrease the rate base by a similar amount. (Exhibit 49 at p. 3-4.)

123. On cross-examination by NPC, Mr. Galloway agreed that the Commission had found in Docket No. 97-6008 "that the benefits of the scrubbers should not be separated from their associated costs." (Tr. at p. 649.) Mr. Galloway also agreed that the Commission accepted Ms. Costanza Ashford's recommendation for NPC, in the same docket, to pro rata a portion of the SO2 allowances based a six-year amortization in the next general rate case. (Tr. at 650-653.)

BCP's Position

124. The BCP's witness, Michael Brosch, recommended that NPC's proposed rate base reduction for the SO2 allowances should reflect the actual unamortized balance of cumulative allowances as of September 30, 2001, this is $15,663,000, not the $9,569,000 NPC proposed. NPC's $9,569,000 rate base adjustment, according to Mr. Brosch, reflected the amortization of SO2 allowances concurrent with the date of each SO2 allowance sale. Furthermore, Mr. Brosch claimed that NPC had not actually recorded any amortization of the SO2 allowances on its books and records, per NPC's response to BCP Data Request No. 13-36.

---

[9] Understood by the Commission to mean "sulfur dioxide".

BCP asserts that allowing NPC's unamortized rate base reduction of $9,569,000 instead of BCP's $15,663,000 would be retroactive ratemaking, which would flow some of the benefits of the SO2 allowances to the shareholders rather than ratepayers. (Exhibit 66 at p.138-139.) Mr. Brosch also testified that he agreed with NPC's proposed $2.611 million annual amortization of SO2 allowances, but that the amortization of the SO2 allowances should start with the effective date of the order in this rate case. (Id. at p. 137 & 142.)

NPC's Rebuttal Position

125. NPC's rebuttal witness, Mr. Rice, testified that there were two different issues being addressed in Docket Nos. 97-6008 and 97-7030. The two issues were: 1) the appropriate division of revenue when the underlying costs of the scrubbers are included in the rates; and 2) the appropriate division of revenues when the underlying costs of the scrubbers are not included in rates, but instead the costs of the scrubbers have been borne by the stockholders for several years. (Exhibit 83 at p. 6.)

126. For the first issue, "revenues when costs are in rates", Mr. Rice claimed that the Commission required the revenues be credited to a deferred account to be returned to ratepayers in a future general rate case. (Id. at 7.) Regarding the second issue, "revenues when costs are not in rates", Mr. Rice claimed that, as a matter of equity, a portion of the revenues should remain with the stockholders to offset the carrying costs of the asset as well as the O & M expenses. Further, he claimed that the issue of equity was addressed in Costanza Ashford's rebuttal testimony in Docket No. 99-6008, and that the Commission agreed with her proposal to match revenues and costs in its Order in Docket No. 97-6008 at page 10, Paragraph 39. (Id. at 8-9.)

127. On cross-examination by the BCP, Mr. Rice agreed that NPC had had free use of $2.27 million from the sale of SO2 allowances on the non-Navajo scrubbers since April 1997. (Tr. at p. 1144.)

Commission Discussion and Findings

128. This is the first opportunity the Commission has ever had to put the SO2 allowances into rates. The Commission acknowledges that the SO2 allowances clearly resulted from the installation of scrubbers on power plants, which are supported by ratepayers. Therefore, the Commission believes that the ratepayers should benefit from the sale of the allowances. None of the parties disputed this. There are, however, additional questions concerning: 1) the amortization period of the SO2 allowances; 2) the accumulated balance of

SO2 allowance credits that should reduce the rate base; and 3) an equity issue regarding how to account for the underlying costs of the scrubbers included in plant-in-service but not included in rates prior to this rate case.

129. Regarding the amortization period in the first question, NPC recommended a six-year period based on: 1) an analysis of the period over which the revenues were received; and 2) Commission opinions in previous dockets, which accepted the six-year analysis. (Exhibit 37 at p. 4-6.) Staff recommended a three-year amortization in order to provide rate stability for ratepayers. (Exhibit 49 at p. 3-4.) Subsequently, on cross-examination, Staff agreed with NPC that the Commission had accepted the six-year amortization in previous dockets. (Tr. at p. 650-653.) The BCP did not challenge NPC's request for a six-year amortization of the SO2 allowances.

130. Although the Commission had previously accepted a six-year amortization, in the current circumstance a six-year amortization is not reasonable. The Commission believes that Staff's observation that rate stability warrants a shorter amortization period is an overriding consideration in this case. Therefore, the Commission finds that a three-year amortization of the SO2 allowances at $5,221,000 per year is appropriate and approved starting with the effective date of this order.

131. The second and third questions, regarding the accumulated SO2 allowances balance (which reduces rate base) and the equity issue, can be dealt with together. NPC proposed an accumulated balance of $9,569,000. NPC's balance reflected starting the amortization of the SO2 allowances concurrent with the dates the allowances were actually sold. As support for its position, NPC argued that in Docket No. 97-6008 at Paragraph 39, the Commission addressed allowing NPC to retain a portion of the SO2 allowances as compensation for carrying costs from having the scrubbers in plant-in-service, but not in rates. (Exhibit 83 at p.13, Exhibit 37 at p. 5, and Revenue Requirements Summary Brief ("Br.") at p. 34.) Starting the amortization of the allowances concurrent with their sale, NPC claimed, provided NPC compensation for its carrying costs since they were not in rates. NPC continued by explaining that once the scrubbers were included in rates, then the remaining unamortized SO2 allowances balance or new SO2 revenues should go to ratepayers. (Br. at p. 34.) However, NPC also agreed on cross-examination by the BCP that it had had the free use of $2.27 million from the sale of SO2 allowances since April 1997. (Tr. at p. 1144.)

132. The Commission believes that to be equitable NPC is entitled to compensation for its carrying costs during the period the scrubbers have been in plant-in-service but not in rates for two reasons: 1) because ratepayers have enjoyed those benefits without paying for them; and 2) because the Commission previously recognized the "equity issue" in Docket No. 97-6008 at p. 10, Paragraph 39, when it found that "…the benefits of the scrubbers should not be separated from their associated costs." (Tr. at p. 649.) The Commission also believes that the use of $2.27 million from the sale of SO2 allowances, which had been credited to the accumulated deferred balance account and will be refunded to ratepayers, does not fully compensate NPC for the lost carrying costs for the plant-in-service. NPC is refunding the $2.27 million to ratepayers.

133. The Commission finds that NPC's accumulated SO2 allowances balance of $9,569,000 is reasonable and therefore approved. The SO2 allowances balance will be credited against NPC's rate base and will be amortized starting with the effective date of this order.

G. Interest Income on the Sale of Water Rights at Coyote Springs

Staff's Position

134. Staff's witness, Mr. Galloway, recommended that interest income on the sale of water rights should be treated above-the-line for ratemaking purposes to be consistent with the Commission's Order in Docket No. 99-4005. (Exhibit 49 at p. 5, and Atch JG-3.)

Commission Discussion and Findings

135. NPC agreed with the Staff's adjustment. Therefore, the Commission finds that the Staff's Coyote Springs adjustment that increased annual revenues by $38,769, and reduced rate base by $103,384, is reasonable and approved.

H. Leasing Revenues

Staff's Position

136. Staff witness, Mr. Galloway, withdrew his adjustment in his Erratum to the Prepared Testimony. (Exhibit 49.)

BCP's Position and NPC's Rebuttal Position

137. BCP's witness, Mr. Brosch, had an adjustment similar to Staff's (Exhibit 66 at Schedule C-5.), which NPC agreed to in its Rebuttal Testimony. (Exhibit 84 at p. 20.)

Commission Discussion and Findings

138. Based on the agreement by NPC and the BCP, the Commission finds the BCP's leasing revenues adjustment reasonable, and approves the BCP's $137,000 increase in revenues.

//

//

//

I. Avoided Leasing Expenses

Commission Discussion and Findings

139. NPC agreed to the Staff's leasing expenses adjustment shown on Exhibit 49 at Attachment JG-7. (NPC Br. at p. 84.) Therefore, the Commission finds this to be a reasonable adjustment and approves a $257,000 decrease in NPC's expenses.

J. Cash Working Capital ("CWC")

Staff's Position

140. Staff's witness, Mr. Galloway, recommended that the Commission reject NPC's CWC, because NPC had provided no support for using non-company specific data in its lead/lag study. (Exhibit 49 at p. 8-9 and Staff's Br. at p. 9.)

MGM's Position

141. MGM's witness, Mr. Garrett, testified that NPC's CWC should be removed from rate base because NPC did not provide a comprehensive and contemporaneous lead/lag study demonstrating that a significant positive CWC investment is required. (Exhibit 63 at p. 37-39.)

NPC's Rebuttal Position

142. NPC's Rebuttal witness, Ms. Franklin, testified that the preparation of a contemporaneous, expensive and time consuming lead/lag study would have been impossible to perform within the time frame established by Assembly Bill ("A.B.") 369. Furthermore, she claimed it was extremely unlikely that a separate lead/lag study for NPC would result in substantially different lag days. (Exhibit 81 at p. 6.) Finally, she stated that in NPC's last rate case that addressed CWC, Docket No. 99-4005, the Commission allowed a hybrid between NPC's proposed study and Staff's proposal. (Id. at 10-11.)

Commission Discussion and Findings

143. The Commission agrees with Staff and MGM, that NPC has not provided valid support for using non-company specific data in its CWC lead/lag study. The Commission also recognizes NPC's claim that the Commission accepted a hybrid calculation in Docket No. 99-4005; a hybrid calculation promoted by Staff, which was considered to be a reasonable level of CWC at that time by the Commission. In Docket No. 99-4005, Staff attempted to establish a reasonable level of CWC for NPC using a previous NPC lead/lag study coupled with the Federal Energy Regulatory Commission's ("FERC") 1/8th standard methodology, which also used NPC

specific data. NPC, however, was not relieved from its obligation in Docket No. 99-4005 to put forth a valid lead/lag study.

144. In the instant docket, neither Staff nor MGM believed there was sufficiently valid data to recommend any CWC. The Commission concurs. Therefore, the Commission finds that NPC has not supported its request for CWC with a valid lead/lag study, and the Commission finds that Staff's CWC adjustment to reduce the rate base by $8,959,000 is reasonable and approved.

K. Customer Information System ("CIS") in Rate Base

NPC's Position

145. NPC's witness, Carol Elmore, testified that the CIS system became operational on February 10, 2002, and, therefore: was not part of CWIP (Construction Work in Progress); that the system was currently used and useful; and that it was currently providing service for its customers. (Tr. at p. 794-795.) Ms. Elmore also testified that the costs of the CIS system have been split 50/50 between Sierra Pacific Power Company ("SPPC") and NPC because direct assignment of the costs would have placed an inappropriately large burden for the investment on SPPC. (Exhibit 55 at p. 3.) Finally, she testified that if the companies had not merged, they both would have had to replace their CIS systems because the systems were old (1980's), and relied on Cobol computer programming language, which is very expensive to program. (Id. at 2.)

Staff's Position

146. Staff's witness, Mr. Galloway, recommended that the CIS system should not be part of rate base and removed it because Staff believed it belonged in CWIP. For CWIP to be part of rate base it must meet a two-part financial test. Staff claimed NPC failed to meet that test. (Exhibit 49 at p. 10.)

147. On cross-examination by NPC, Mr. Galloway agreed that once the CIS system became used and useful (February 10, 2002), that Allowance for Funds Used During Construction ("AFUDC") would no longer accrue to it because it would be classified as plant-in-service. Mr. Galloway also agreed that once the CIS system became operational, the ratepayers would start benefiting from the system, but NPC would not be able to recover its costs for two more years. (Tr. at p. 663.) Additionally, Mr. Galloway agreed that NPC had no choice when to file this rate case or what test period would be. (Id.)

MGM's Position

148. MGM's witness, Mr. Garrett, recommended that the CIS system be removed from rate base. He testified that NPC would experience no significant financial harm if the costs of the CIS System were left in CWIP and allowed to continue accruing a return through AFUDC. (Exhibit 63 at p. 31-34.)

BCP's Position

149. BCP's witness, Mr. Brosch, testified that the CIS system should be removed from rate base for several reasons. His primary reason was that the CIS system was in CWIP at the end of the Certification Period, therefore, inclusion of it in rate base must be based on a showing of financial hardship. (Exhibit 66 at p. 10.)

NPC's Rebuttal Position

150. NPC's Rebuttal witness, Mr. Rice, testified that the CIS system should be allowed in rate base because the project went into service on February 10, 2002, prior to when rates will go into effect in this case. He also testified that once the plant was placed in service on February 10, 2002, NPC would not be able to continue to accrue AFUDC on it. As a result, he stated that NPC would not earn a return on its investment until the next rate case. (Exhibit 83 at p. 27.)

Commission Discussion and Findings

151. Whether or not to place NPC's new CIS System in rate base is a question of first impression for the Commission. The Staff, MGM and BCP witnesses were correct- for CWIP to be included in rate base NPC would normally need to show a financial need. However, Staff also quoted Docket Nos. 91-5032 and 91-5055 that "…whether or not the inclusion of CWIP in rate base is the 'right tool for the job' depends on the particular situation the utility is in at the time rates are set." Although the Commission would not ordinarily allow CWIP in rate base unless the utility could show significant financial hardship, this is a situation where rates have not been set and the CIS System is undeniably in service.

152. Therefore, in reaching a decision in this case, the Commission focuses on the particular phrase in Docket Nos. 91-5032 and 91-5055 that would allow CWIP in rate base depending "on the particular situation the utility is in at the time rates are set." (Staff's Br. at p. 10.) In the current case, the Commission finds that the CIS System is used and useful prior to rates being set. Further, the Commission notes that if the CIS System did not go into rates now, it would be at least two more years before NPC could put it into rates. The Commission also notes that the CIS System is no longer classified as CWIP on NPC's books and records, but

instead is classified as plant-in-service. Therefore, the Commission finds this to be a reasonable request by NPC and places NPC's CIS System in rate base and thus into rates.

L. Other Rate Base Items

Staff's Position

153. Staff's witness, Mr. Galloway, recommended reducing "other rate base" for certain adjustments authorized by the Commission in Docket No. 99-4005. These adjustments were: updating the 13-month average ending with the Certification Period; removing the deferred balance of the organizational study; and, using the September 30, 2001 Balance of the Pension Liability because the Balance consistently increases each month, unlike other balances in this adjustment. (Exhibit 49 at p. 11 and Atch JG-10.)

BCP's Position

154. The BCP's witness, Mr. Brosch, recommended that fuel inventories at the Harry Allen Station and the Sunrise Station be annualized. (Exhibit 66 at p. 17.) NPC accepted these proposed adjustments to reduce rate base by $217,000. (NPC Br. at 22.) Mr. Brosch also recommended that the 13-month average of the prepayments balance be adjusted to eliminate an unusual and non-recurring large bulk power transaction with Aquila during the test year. (Exhibit 66 at 19.)

NPC's Rebuttal Position

155. NPC's rebuttal witness, Mary Simmons, testified that utilizing the 13-month average prepayments balance eliminated the unusual and non-recurring Aquila transaction by its very calculation. She claimed that Mr. Brosch was trying to reduce revenue requirements with no regard to how the adjustment should be made. (Exhibit 84 at 18.)

156. NPC's second rebuttal witness on "other rate base" adjustments, Mr. Rice, testified that NPC accepted the following Staff adjustments proposed in Exhibit 49 at Attachment JG-10: 1) Uncollectible Accounts Reserve at line 4 of Atch JG-10; 2) Injuries and Damages Reserves at line 5 of Atch JG-10; 3) Vacation and Leave Accrual at lines 7-8 of Atch JG-10; 4) Reduction to Customer Advances to 9/30/01 at line 11 of Atch JG-10; and 5) Increase to Levelized Lease Payments to 9/30/01 at line 12 of Atch JG-10. (Exhibit 83 at 19.)

Commission Discussion and Findings

157. NPC accepted several of Staff's adjustments in their rebuttal testimony, and did not dispute the rest. Therefore, the Commission finds that Staff's Other Rate Base deductions

outlined in NPC's Closing Brief Regarding Revenue Requirement Issues at p. 19, Attachment I.A.5, totaling $8,892,000, are reasonable and approved.

158. However, the Commission believes NPC correctly stated in its rebuttal testimony that the effect of utilizing the 13-month average on the prepayments balance is to eliminate the unusual and non-recurring Aquila transaction by its very calculation. Therefore, the Commission finds that Mr. Brosch's normalization adjustment of $1,108,000 for the Aquila transaction is inappropriate, and the Commission rejects it.

159. NPC did accept Mr. Brosch's fuel annualizing adjustment of $217,000 reducing rate base. Therefore, the Commission finds Mr. Brosch's adjustment of a $217,000 reduction to rate base to annualize the fuel inventories at Harry Allen and Sunrise Stations to be reasonable and is therefore approved.

M. Amortization of Intangibles

Staff's Position

160. Staff's witness, Mr. Galloway, recommended reducing the rate of amortization on certain items of intangible plant because the balances are fully amortized in less than a year. (Exhibit 49 at Atch JG-6.) Furthermore, he stated that to allow the amortizations to continue at their present rate would allow an extra year of expenses in rates. (Id. at 7.)

NPC's Position

161. NPC's witness, Mr. Rice, testified that the Commission, in Docket No. 93-11045, authorized NPC to take an eight-year amortization period for these same items, but ordered NPC not to include them in a general rate case with a test year that ends after December 31, 2001. (Exhibit 83 at p. 18.)

Commission Discussion and Findings

162. The Commission finds that the intangible adjustment is similar to the CIS System adjustment only in reverse. In that adjustment, the Commission allowed the CIS System in rate base even though it was classified on NPC's books and records as CWIP when the Certification Period ended. However, because the CIS System became plant-in-service before rates were set, the Commission allowed it in rate base (see decision above). In this instance, the Certification Period ends September 30, 2001, three months prior to December 31, 2001; however, rates won't be effective until April 2002, well beyond the December 31, 2001 test year mentioned in the Commission's Order in Docket No. 93-11045. Therefore, the Commission finds, to be

consistent with the CIS System adjustment, Staff's Intangible Amortization reduction to expenses of $1,181,000 is reasonable and therefore approved.

N. Management, Professional, Administrative and Technical ("MPAT") Short Term Incentive Program ("STIP") and Bargaining Unit ("BU") STIP

NPC's Position

163. NPC's witness, Mary Jane Reed, testified that as part of the merger with SPPC, NPC and SPPC re-evaluated and redesigned their incentive programs for MPAT employees. The STIP, which is part of the Total Rewards[10] concept, provided incentive pay to reward eligible employees for individual performance and for contributing to NPC's overall performance. Incentive awards are based on corporate goals, business unit goals, and individual results and competency improvements. Incentive awards are calculated using a percentage associated with each salary band, ranging from 5 percent to 25 percent, at target performance. If goals are met, the percentage is applied to the employee's base pay. If goals are exceeded, an employee can earn up to 150 percent or 200 percent of the incentive award, depending on the position. All regular MPAT employees, full-time or part-time, hired prior to the end of the plan year are eligible. Payout may be pro-rated for partial year employment. (Exhibit 38 at p. 10.)

164. Ms. Reed also testified that wages for approximately 920 employees were established through three collective bargaining agreements with Local Union No. 396, International Brotherhood of Electrical Workers ("IBEW"). The collective bargaining agreements for generation plant workers were modified to accommodate generation plant divestiture and became effective June 25, 1999, which agreements expired February 1, 2002. (Id. at 11-12.)

165. Further, Ms. Reed testified that since the commencement of the program, NPC had continued to meet and improve its quality of service, system performance reliability and cost reduction goals. When combined with its quality of service and reliability performance, cost reductions have equated into increased customer satisfaction. In addition, she claimed, for the second year in a row, NPC and SPPC had been awarded the "Best of the West" award by J.D. Power and Associates for customer satisfaction for mid-sized electric utilities. Thus, she claimed, customers have benefited from the STIP through excellent customer satisfaction performance. (Id. at 11.)

[10] A program that considers traditional pay, traditional benefits, workforce development and work environment, which is benchmarked within the 50th percentile of a comparison group.

166. On cross-examination by NCCEU, Ms. Reed stated that the test year did not include incentive payments for executives. (Tr. at p. 539.)

167. On cross-examination by Staff, Ms. Reed agreed that in Docket No. 91-5055, the Commission expressed concern that in an incentive package financial goals should be weighted 50/50 with customer service goals. (Tr. at p. 550-553.) Ms. Reed testified that the business unit results of the incentive program benefit customers through efficient operations, which clearly benefits customers' service. (Tr. at p. 555.) Ms. Reed also testified that there was a provision in the STIP for not paying incentives or bonuses if there was a concern with the financial condition of NPC. (Tr. at p. 557.)

Staff's Position

168. Staff's witness, Lew DeWeese, recommended that the Commission disallow the total STIP costs paid to MPAT employees equaling $4,507,504, because: a) the incentive program did not provide for a mechanism which would override the granting of any bonuses during times of poor overall financial performance such as NPC had recently experienced; b) the goals related to customer service were not given equal weight with financial goals; c) the goals were not based on indicators of performance that were within direct control of management; and, d) the goals of the program were not consistent with the regulatory goal of reliable service at reasonable rates. (Exhibit 52 at p.1-2.)

169. Mr. DeWeese also testified that the Commission should disallow the total STIP costs paid to the BU personnel equaling $555,069, because: a) these costs were non-recurring; b) a large portion of these bonuses were for the work done on the CIS System, which was not on line during the Test or Certification Period; and, c) the plan did not have a mechanism which would override the granting of any bonus during times of poor financial performance such as NPC had recently experienced. (Id. at 2.)

170. On cross-examination by NCCEU, Mr. DeWeese stated that there was no executive STIP in the revenue requirement, but the STIP did include NPC's management. He also stated he did not know the cut-off between management and executives for STIP purposes. (Tr. at p. 703.)

171. On cross-examination by NPC, Mr. DeWeese testified that his recommendation to disallow STIP was based on previous Commission orders. (Tr. at p. 704.) He also testified that contrary to NPC's position that NPC's STIP matrix does weigh financial goals and customer satisfaction goals 50/50, Staff's position was that it was not a balanced plan. (Tr. at p. 712-713.)

Mr. DeWeese testified that in Docket Nos. 91-5032 and 91-5055 the Commission addressed executive incentive pay and bonuses. (Tr. at p. 713.) But Mr. DeWeese's testimony in the current case did not discuss the Commission's most recent pronouncements on the STIP in Docket No. 99-4005, which allowed incentive compensation in rates based, to a large extent, on Mr. DeWeese's own recommendation in that case. (Tr. at p. 718-722.) When questioned on this, Mr. DeWeese stated that he did not bring it up in that case because ratemaking is a dynamic process. (Tr. at p. 723.) Mr. DeWeese did agree that Mr. Garrett brought the STIP issue to the Commission's attention in Docket No. 99-4005, although Mr. DeWeese stated he would have to review Mr. Garrett's testimony again to determine how much weight the Commission gave it therein. (Tr. at p. 724.)

172. On redirect, Mr. DeWeese stated that his interpretation of Docket No. 91-5055 was that the issue of executive bonuses applied to all of NPC's employees and not just to executives. (Tr. at p. 728-729.)

173. When questioned by the Commission, Mr. DeWeese agreed that past orders are not binding upon the Commission, they are only advisory. He also agreed that Staff's positions in previous dockets are not binding on Staff in future dockets. (Tr. at p. 735-736.)

<u>NPC's Rebuttal</u>

174. NPC's rebuttal witness, Ms. Reed, testified that NPC's STIP plan rewards eligible employees for individual performance, as well as for contributing to NPC's overall service and financial performance. She also stated the STIP was an essential component of NPC's total cash compensation strategy which was designed to: (1) attract and retain the workforce needed to continue to provide excellent service to NPC's customers; (2) motivate employees to embody the values of the organization and acquire skills and competencies to meet the growing needs of NPC's customers; (3) address the skill and talent needs of different parts of NPC's business; (4) create a sense of ownership and commitment among employees; (5) reinforce employee self-sufficiency; and, (6) recognize the diverse needs of employees. (Exhibit 87 at p. 3.) Ms. Reed also testified that NPC had been able to keep downward pressure on base salary increases and other related benefits by relying on variable, incentive pay in the form of STIP. STIP costs were an essential component of NPC's basic labor costs and should not be eliminated from the revenue requirement. (<u>Id.</u> at 4-5.) Furthermore, Ms. Reed testified that NPC must provide a level of compensation that was competitive within the market. If NPC were unable to pay its STIP because of a ruling in this proceeding, it would have to increase base salaries so that

compensation levels were commensurate with the total compensation provided in the market. (Id. at 8.)

175. Finally, Ms. Reed testified that contrary to Mr. DeWeese's claims, NPC's STIP gives more weight to customer service and cost effectiveness goals than it does to financial goals. She stated that for the 2000 Performance Year, NPC had developed the STIP consistent with the Commission's stated goal of fostering reliable service at reasonable rates using the Balanced Scorecard Framework ("Framework"). This Framework included measures around financial performance, customer satisfaction, operational efficiency and productivity, and workforce excellence. These four categories were measured at the corporate level (SPR) as well as the Business Unit level (NPC/SPPC). Management employees also set their individual goals and objectives around these four categories. The measures in the 2000 STIP benefited NPC's customers by promoting reliable service at reasonable rates. In addition, a total of 50 points out of a possible 70 were directly related to the customer service goal of providing reliable energy and reasonable rates. Ms. Reed explained that all 70 points have an indirect impact on this goal. (Id. at 9-10.)

Commission Discussion and Findings

176. In past opinions and orders, the Commission has discussed the issue of incentive compensation and has expressed support for such plans as long as the goals of the plans are consistent with the regulatory goal of reliable service at reasonable rates. In this case, Staff recommends that the Commission disallow NPC's total STIP costs paid to the MPAT and BU employees of NPC based primarily on past Commission orders. Mr. DeWeese stated his belief that these orders required NPC, among other things, to balance customer service goals equally with financial goals and to provide a mechanism that would override the payment of bonuses in times of poor financial performance. However, in the most recent Commission Order to address this issue, Docket No. 99-4005, Mr. DeWeese recommended that the Commission accept NPC's STIP plan even though the plan's goals were weighted 40 percent to customer satisfaction and 60 percent to earnings per share. (NPC's Br. at 75.)

177. NPC testified that under the current STIP plan bonuses were not paid during times of poor financial performance and customer service measures are weighted more heavily than financial performance measures. Ms. Reed also testified that NPC's STIP plan is an essential component of its basic labor costs and if eliminated NPC would have to increase total compensation so that its compensation levels would remain competitive with the marketplace.

178. Based on the evidence, the Commission finds that NPC's STIP program does meet the Commission's regulatory requirement of reliable service at reasonable rates. However, the Commission is aware that certain managers and employees, apart from the executives, are in positions that are more closely aligned with shareholder interest than ratepayer interest. For example, managers and employees of the Investor Relations and Public Relations departments are employed to enhance NPC's image primarily for shareholder benefit, and there may be other similarly situated employees. As a result, some of these employees' STIP may be the responsibility of shareholders, not ratepayers. The Commission will examine this issue more fully in the next general rate case. At this time, the Commission finds NPC's adjustments for MPAT and BU STIP reasonable and therefore approved.

O. Performance Bonus

Staff's Position

179. Staff's witness, Mr. DeWeese, recommended that the total performance bonus costs paid to NPC's employees, equaling $1,527,899, should be disallowed because: a) the costs are non-recurring; b) a large portion of these bonuses were for work done on the Customer Information System (CIS), which was not on line during the Test or Certification Period; and, c) the plan does not have a mechanism which would override granting bonuses during times of poor overall financial performance. (Exhibit 52 at p. 2.)

BCP's Position

180. The BCP's witness, Mr. Brosch, proposed to normalize the performance bonus adjustment because NPC indicated that it does not anticipate incurring the test year level of performance bonuses each year. As a result of NPC's response to Data Request New #OS R03, Mr. Brosch normalized the performance bonus to $300,000 on a going-forward basis. (Exhibit 66 at p. 117 and 120.)

NPC's Position

181. NPC accepted the BCP's normalized adjustment of $300,000 for Performance Bonuses. (NPC's Br. at p. 77.)

Commission Discussion and Findings

182. The Commission agrees with Staff's position in general that large non-recurring costs should be removed from the test year. The performance bonus adjustment agreed to by the BCP and NPC removes the large non-recurring bonuses paid in the test year. As for Staff's other arguments concerning the CIS system (which the Commission did allow in rate base (see CIS

System Decision above)) and the mechanism to override payment of bonuses in times of poor financial performance (which NPC has addressed in its current STIP program); the Commission believes these arguments have been dealt with by NPC and are not valid issues at this time.

183. Therefore, the Commission finds that NPC's performance bonus program is reasonable and that a $300,000 amount for performance bonuses on a going-forward basis in NPC's revenue requirement is reasonable and approved.

P. Employee Benefits

Staff's Position

184. Staff witness, Sandy Small, recommended reducing employee benefits by $91,000 because of a transfer error on Statement I-29 of NPC's filing. (Exhibit 53 at p. 2.)

Commission Discussion and Findings

185. NPC did not dispute this adjustment. Therefore, the Commission finds the $91,000 correction of the transfer error reasonable and approved.

Q. Supplemental Executive Retirement Plan ("SERP")

NPC's Position

186. NPC's witness, Jack Atkins, testified that in Docket No. 91-5055, SERP benefit costs were not included in NPC's revenue requirement. Therefore, he stated, the Commission had not ruled on this issue. (Tr. at p. 529-530.) Mr. Atkins also testified that the executive compensation included both incentive and non-incentive based compensation. Non-incentive based compensation and benefits are designed to provide compensation and benefits consistent with market standards. Therefore, non-incentive compensation and benefits are not variable and are not linked to performance measures. Examples of non-incentive compensation and benefits are base pay, qualified retirement benefits, supplemental retirement benefits and medical benefits. Mr. Atkins continued to explain that NPC's supplemental retirement plan for executives was a fixed benefit, payable at retirement and not attributable to any performance measure or customer satisfaction goals. Rather, the plan was designed to provide market-based benefits to executives. Therefore, NPC asked the Commission to include the costs of this base-compensation plan in costs of service. (Exhibit 39 at p. 10.)

Staff's Position

187. Staff's witness, Ms. Small, testified that the Commission previously considered and rejected NPC's request for SERP in Docket Nos. 91-5032 and 91-5055. She stated that in that decision, the Commission stated plans must be consistent with the regulatory goal of reliable

service at reasonable rates, and goals related to customer service must be given equal weight with financial goals. She claimed that the only evidence offered by NPC was the assertion in Mr. Atkins' direct pre-filed testimony that SERP was used to retain, attract and motivate selected executives by offering a competitive level of retirement. Ms. Small continued stating that SERP was customized to benefit specific employees, yet also provided for revoking the designation of an employee as a participant in the Plan. Ms. Small also claimed that NPC did not provide a comparative market study that would support Mr. Atkins' assertions and that would assist the Commission in determining how many similarly situated utilities include the recovery of SERP in retail rates. Absent that information, and absent information that would establish that SERP had changed since Docket Nos. 91-5032 and 91-5055, Ms. Small recommended that the SERP expense of $1,311,000 should be removed from the revenue requirement. (Exhibit 53 at p. 2-3.)

MGM's Position

187. MGM's witness, Mr. Garrett, testified that the costs of supplemental retirement plans are generally excluded from rates for at least two reasons. First, participants in a supplemental executive retirement plan generally include only officers, executives and key employees of NPC. Since officers of any corporation have a duty of loyalty to the corporation itself and not to the customers of that corporation, these individuals typically put the interest of shareholders first. Many regulators are inclined to exclude executive bonuses, incentive compensation and supplemental benefits from utility rates, understanding that these costs would be better borne by the utility shareholders.

188. Second, NPC's pension plan covers all employees including executives, and ratepayers pick up all of these costs. According to MGM, the costs of supplemental retirement plans are additional costs to "sweeten the pot" for executives. As such, they are not considered to be necessary costs of providing utility service. Typically, ratepayers pay for all of the normal costs of employee retirement plans. Additional costs to supplement the retirement of utility executives are generally considered the responsibility of the shareholders. Thus, Mr. Garrett proposed removing SERP of $1.604 million from operating expense. (Exhibit 63 at p. 43-44.)

NPC's Rebuttal Position

189. NPC's rebuttal witness, Ms. Reed, testified that SERP was an appropriate mechanism for providing retirement benefits to executives and was a commonly used component of executive benefit packages offered in the utility and other industries. She stated that without SERP it would be difficult to attract and retain the experienced and highly motivated executives

needed to lead NPC in the ever-changing utility environment and marketplace. (Exhibit 87 at p. 14-15.)

Commission Discussion and Findings

190. Mr. Garrett and Ms. Small stated that SERP programs were customized to benefit specific employees. In fact, NPC's program is a fixed benefit program for executives, payable at retirement. The plan is designed to provide market-based benefits for executives over and above their regular retirement benefits. The Commission believes this program is very appropriate to attract and to keep qualified executives.

191. Yet, Mr. Garrett made some very valid points when he testified that participants in a SERP program are generally only executives and key employees of NPC. Since executives of any corporation have a duty to the corporation itself and not to its customers, these individuals typically put the interests of the corporation and shareholders first. Furthermore, the costs of the SERP are additional costs above regular pension plans to sweeten the pot for executives. As such, they are not considered to be necessary costs of providing utility service. Typically, ratepayers pay for all the normal costs of employee retirement plans.

192. The Commission agrees with the MGM witness Mr. Garrett; the SERP should be the responsibility of the shareholders. Therefore, the Commission finds the adjustment to remove $895,000 of SERP from NPC's expenses to be reasonable and approved.

R. Advertising Expense

Staff's Position

193. Staff's witness, Ms. Small, testified that the Commission should disallow advertising expenses for two programs. First, the *Fortune* magazine project was produced four times a year and discontinued in 2001. The cover wrap was image-enhancing advertising. It was not conservation related because it used more space on Harrah's Lake Tahoe and feel-good photography than conservation, safety, or other advertising allowed by NAC 704.295. The test year costs of the discontinued campaign were $24,119. Second, in response to BCP Data Request Number 15-09, NPC attached a schedule of payments for expenses relating to various advertising. Those expenses were incurred from January through May 2000. A total of $84,433 was paid outside the test period and should be excluded from revenue requirement. (Exhibit 53 at p. 3-4.)

//

//

NPC's Rebuttal Position

194. NPC's rebuttal witness, John Brown, testified that he agreed with Staff's *Fortune* magazine adjustment of $24,119. (Exhibit 79 at p. 15.) Mr. Brown testified that he did not agree with Ms. Small's out-of-period adjustments because, he claimed, Ms. Small based her conclusions on a review of test period vouchers that excluded certain vouchers paid after the test period. As was communicated to Ms. Small during her review, NPC utilized a "cash basis" for all vouchers less than $100,000 to be included in revenue requirements, after adjusting for extraordinary items. Consequently, he stated, NPC included no expenses in revenue requirements for items paid outside of the test year. Ms. Small's proposed adjustments, on the other hand, only included expenses that were incurred for services prior to the beginning of the test year but actually paid in the test year. Ms. Small's review did not include expenses that were incurred in the test year, but paid subsequent to May 31, 2001. NPC stated that it was inappropriate for Ms. Small to include only one side of the adjustment. Mr. Brown proposed that Ms. Small's adjustment be offset with expenses incurred during the test period but paid subsequent to the end of the test year in the amount of $59,175, as detailed at Exhibit JEB-Reb-1. (Id. at 15-16.)

Commission Discussion and Findings

195. The Commission agrees with NPC that an out-of-period expense analysis needs to cover both the month prior to the beginning of the test year (May 2000) and the month immediately following the end of the test year (June 2001) to be an accurate analysis. The Commission also believes, from a materiality stand point, that NPC's policy of utilizing a "cash basis" for vouchers less than $100,000 for inclusion in the revenue requirement is appropriate.

196. Therefore, the Commission finds that both the Staff's reduction in advertising expenses of $84,433, which includes out-of-period expenses less than $100,000 and NPC's subsequent increase in expenses of $59,175, which also includes expenses less than $100,000, to be inappropriate and rejects it. NPC agreed with Ms. Small's $24,119 adjustment for *Fortune* magazine and therefore, the Commission finds this to be a reasonable adjustment and approves a $24,119 reduction to advertising expense.

//

//

//

//

S. Injuries and Damages

Commission Discussion and Findings

197. The Parties involved in this portion of the proceeding reached agreement with this adjustment as reflected on Exhibit 44. The agreement reduces NPC's request for recovery from $807,000 down to $139,000. (Tr. at p. 582-583.)

198. The Commission finds NPC's request for $139,000 for injuries and damages to be reasonable and is therefore approved.

T. Out of Period Expenses

Staff's Position

199. Staff's witness, Ms. Small, recommended that out-of-period expenses incurred either prior to, or subsequent to the test year, but paid during the test year, should be removed from the revenue requirement since the expenses were not incurred during the test year. After selecting a sample of expenditures from NPC's Master Data Response MDR-12 (Accounts Payable), Ms. Small reviewed NPC's invoices, selecting items needing further review. Exhibit 53 at Attachment SKS-6 listed $920,332 in out-of-period expenses, which Ms. Small recommended removing from the test year. She stated that NPC addressed its out-of-period expenses in its Statement H-22 by adding expenses incurred during the test year but paid subsequent to May 31, 2001, and removing items paid in June 2000 incurred prior to June 1, 2000. However, NPC's procedure was to only review amounts exceeding $100,000 in June 2000 and June 2001. Ms. Small testified that her review covered items equal to or more than $20,000 for the same months. (Exhibit 53 at p. 5.)

200. On cross-examination by NPC, Ms. Small testified that when she performed her out-of-period analysis she only tested the front part of the test year (May 2000) for expenses but did not extend that analysis to the end of the Test Year (June 2001). (Tr. at p. 743-744.)

NPC's Rebuttal Position

201. NPC's rebuttal witness, Mr. Brown, testified that Ms. Small's proposed adjustment only included expenses that were incurred for services prior to the beginning of the test year but actually paid in the test year. He stated her review did not include expenses that were incurred in the test year but paid subsequent to May 31, 2001. Again, Mr. Brown stated that it is inappropriate to only include one side of the adjustment. Mr. Brown proposed that Ms. Small's adjustment be offset with expenses incurred during the test period but paid subsequent to

the end of the test year (June 2001) in the amount of $1,391,541.46, as detailed at Attachment JEB-Reb-2. (Exhibit 79 at p. 16-17.)

Commission Discussion and Findings

202. The Commission agrees with NPC that an out-of-period expense analysis needs to cover both the month prior to the beginning of the test year (May 2000) and the month immediately following the end of the test year (June 2001) to be an accurate analysis. The Commission also believes, from a materiality standpoint, that NPC's policy of utilizing a "cash basis" for vouchers less than $100,000 for inclusion in the revenue requirement is appropriate.

203. Therefore, the Commission finds that both the Staff's reduction in expenses of $920,332, which includes out-of-period expenses less than $100,000, and NPC's subsequent increase in expenses of $1,391,541, which also includes expenses less than $100,000, to be inappropriate and rejects these adjustments.

U. Capitalization & Amortization of Expenditures

Staff's Position

204. Staff's witness, Ms. Small, testified that there were four expenses that should be amortized. First, UMS was retained in response to the SPR and Portland General Electric plan. NPC has since used the information developed for benchmarking purposes. NPC stated in response to BCP Data Request Number 33-4 that it might not continue to need this service. Ms. Small recommended these expenses be amortized resulting in a $133,000 revenue requirement reduction. Second, Paris/Bally's expense is for a meter-readers' conference, this was a nonrecurring event. Amortizing this expense resulted in a $40,244 reduction in revenue requirement. Third, Morris, Pickering & Sanner expenses related to a contract dispute with a qualifying facility. This amortization resulted in a $160,000 reduction in revenue requirement. Finally, NPC included expenses for a search firm to secure a new chief financial officer. Amortizing these costs over two years resulted in a $41,946 reduction in revenue requirement. (Exhibit 53 at p. 6.)

205. Ms. Small testified that there were three expenses that should be removed from the revenue requirement. First, NPC participated in an incentive marketing program called Builder's Edge to encourage contractors to build all electric units. Builders were paid $250 for each unit. Marketing to encourage the use of electricity is clearly designed to promote fuel choice and increased use of electricity and electrical appliances. In Docket Nos. 91-5032 and

91-5055 the Commission disallowed this type of expense. NPC included $116,500 in revenue requirement for this program. (Id.)

206. Next, NPC included in expenses some purchases that should have been capitalized. NPC expensed a payment to Nevada Title for land at a substation. Turbo Care was paid for blades, and Ryan Mechanical worked on a cooling tower retrofit. NPC agreed the items should be capitalized. Finally, E-Three Custom Energy is an affiliate of SPR. NPC agreed that the inclusion of this $20,100 expense was an oversight by NPC. (Id.)

207. Ms. Small stated that the result of removing these items from the revenue requirement was an $851,000 reduction. (Exhibit 53 at p. 7.)

Commission Discussion and Findings

208. NPC does not dispute these adjustments by Ms. Small. The Commission, therefore, finds that Staff's adjustments of $1,226,000 for amortization of expenses (Staff's Br. at p. 19, line 16) over two years and of $163,000 for the removal and capitalization of certain expenses (Staff's Br. at 2, line 11) from the test year to be reasonable and approved.

V. Harry Allen Station and Other Not Used Plant

Staff's Position

209. Staff's witness, John Candelaria, testified that $28,099,805 of plant additions, which consist of $15,451,443 attributed to the Harry Allen Station and $12,648,362 attributed to transmission/distribution facilities and equipment, be removed from the rate base. (Exhibit 46 at p. 2.) Mr. Candelaria also testified that the plant additions associated with his proposed adjustment are not used and are not providing benefits to NPC's customers.

210. In Staff's view, utilities are entitled to place in rate base their facilities that are used and useful in rendering service to their customers. A customer's rates appropriately pay for facilities that are used and useful in providing utility service to them. Mr. Candelaria claimed it is a long-standing and well-recognized rate setting principle that facilities that are not used and useful in providing utility service should not be paid for by customers in their rates. (Id.)

211. In this case, Mr. Candelaria claimed, NPC had built certain facilities to accommodate future growth over the coming years. The appropriate treatment for excess plant that may be built now to take advantage of design and construction costs savings, but which is used in the future to serve customers is to place those costs in Plant Held for Future Use. Mr. Candelaria claimed that it is necessary, therefore, to segregate those costs for the excess portion of a facility built to accommodate future growth. He stated that he did not cut any fine lines

between what is presently "used and useful" and what is built to accommodate future growth. (Id. at 3.)

212. NPC has experienced significant customer growth for many years, and it appears that the growth will continue. Mr. Candelaria stated that NPC continued to build to meet the growth, but facilities that won't be used for several years cannot currently be charged to customers. The adjustments that he described in his testimony focused on facilities that are not going to be used for several years. (Id. at 3-4.) Mr. Candelaria also testified that his proposed adjustments are being made because the plant additions associated with the adjustment are excess equipment. No adjustments are being recommended because of imprudence or because the equipment is not considered useful. Mr. Candelaria expected to apply the prudence, "used and useful" concept to the disallowed plant additions at some point in the future, possibly NPC's next general rate case which he expected would be filed with the Commission in two years. (Id. at 4.)

213. On cross-examination by USAN, Staff's witness testified that the $8,300,000 adjustment for the Harry Allen Station plant excluded a related adjustment to depreciation and deferred income tax effects. (Tr. at p. 592-593.) Mr. Candelaria also testified that he was uncertain whether the disputed portion of the Harry Allen Station plant was built pursuant to an approved resource plan. (Tr. at p. 594.) Mr. Candelaria further stated that the carrying costs for the plant, which were included in Plant Held for Future Use, would be the responsibility of NPC's shareholders. (Tr. at p. 595-596.)

214. On Redirect from Staff's Counsel, Mr. Candelaria stated that Staff's adjustment was for plant that was designed and installed to be used for future customers. (Tr. at p. 608.) He clarified that the $8.3 million referred to in Mr. Crowell's cross-examination for USAN actually referred to common facilities at the Harry Allen Station plant that were built to accommodate more than one CT (Combustion Turbine). (Tr. at p. 609.) Mr. Candelaria also stated that the "91-5055 costs", referred to in his testimony, were separate from the $8.3 million common costs, and included site development done in the vicinity of Harry Allen Station. (Tr. at p. 609-610.) Exhibit 47 identified several "91-5055 costs" from NPC, which could not be verified or reconciled by Staff. The costs ranged from $3.512 million to $4.4 million. (Tr. at p. 611-613.)

215. In answer to questions from the Commission, Mr. Candelaria stated that there were economies of scale associated with building some of the equipment that is currently on the Harry Allen Station site. In fact, Mr. Candelaria indicated he did not have a problem with the

fact that the site was over-sized and that, in general, over-sizing was a good management practice. (Tr. at p. 627-628.) Mr. Candelaria also stated that the Commission's policy on the expansion of the Harry Allen Station site has changed over the years based on what was happening with Nevada's utility industry. In summary, Staff's recommendation is that the items discussed above should not be in rate base. (Tr. at p. 627-628.)

NPC's Rebuttal Position

216. NPC's rebuttal witness, Herbert Goforth, testified that, with very few exceptions, all of the transmission and distribution substation facilities and equipment totaling $12,648,362, are currently being used. Mr. Goforth further testified regarding the few exceptions that NPC's position is that facilities prudently installed to accommodate near term load growth on the system should be allowed in rate base. (Exhibit 68 at p. 11.)

217. Included in the substation facilities, there are a limited number of specific infrastructure units that were prudently installed that have not yet been used by NPC to serve their customers, but NPC expects to make use of them in the near future. These facilities include: (1) a Bank 1 Foundation at Peace Substation; (2) a Bank 4 Foundation, 7-138 kV Bus Pedestal Foundations and 1-138 kV Bus Support Foundation at McDonald Substation; (3) a Bank 2 Foundation at the Avera Substation; (4) a Bank 2 Foundation at the Ford Substation; (5) a Bank 5 Foundation at the Northwest Substation; and, (6) a Bank 3 Foundation at the Quail Substation. Mr. Goforth stated that these facilities were constructed at the same time as the rest of the substation equipment for the following reasons: to avoid the significantly increased costs associated with construction at a later date; to accommodate near term load growth; and, because, their relative proximity to energized equipment would make construction at a later date either dangerous to workers or result in scheduled outages to customers. If the Commission does not allow NPC to include these items in rate base, Mr. Goforth stated that the appropriate adjustment to rate base for these facilities is $355,321 as set forth in Attachment HG-2 to this testimony. (Id. at 11-12.)

218. Another NPC rebuttal witness, Craig York, testified that all of the facilities at the Harry Allen Station are being used. The Harry Allen Station consists of the following components and systems: (1) combustion turbine generator; (2) interconnecting facilities; (3) site and site preparation, grading and roads; (4) step-up transformer and equipment; (5) fuel systems (gas and oil backup); (6) fuel oil tank; (7) evaporation ponds; (8) distributed control systems; (9) auxiliary generating system; (10) control and administration buildings; (11) water tanks; (12)

water systems; (13) environmental control systems; and, (14) communication systems. Each and every one of these components/systems of the Harry Allen Station, he claimed, is being used to provide service to customers. Mr. York stated that neither Mr. Candelaria nor Mr. Dan Gabour could point to any one of these systems or components and show that it had not been used for its intended purpose. (Exhibit 69 at p. 3.)

219. Mr. York also testified that he did not agree with Mr. Candelaria's recommendation to exclude the Harry Allen Station site development costs. The site development costs for Harry Allen Station total $7,174,479.11. Of this amount, Mr. York testified that $3,512,349.26 relates to direct costs and $3,662,129.85 relates to AFUDC. These figures were provided to Staff in data request Staff-On-Site 49. In Docket No. 91-5055, NPC sought approval from the Commission to include $4,999,999.00 for Harry Allen Station site development costs in rate base. He claimed that the Commission denied the rate base request at that time, and instead allowed NPC to accrue AFUDC on the site development costs. The Commission advised in Docket No. 91-5055 that NPC should bring the costs forward to the Commission when facilities were constructed on site. A very significant amount of facilities have been constructed on the site, and, pursuant to the direction of the Commission, NPC was now seeking recovery of the costs and the accompanying AFUDC[11]. (Id. at 11.)

220. Mr. York also did not agree with Mr. Candelaria's statement that NPC was unable to demonstrate whether the site costs were legitimate. He stated that Staff was provided all of the work orders and backup documentation for the site development costs. Because of timing constraints Mr. Candelaria was unable to fully analyze the individual invoices for the work orders. NPC representatives have, however, reviewed the invoices and have removed the costs that were exclusively associated with the research and development of a coal fired unit prior to 1991, which is why the original amount of nearly 5 million dollars has been reduced to approximately $3.5 million. (Id. at 13.)

221. Regarding the methodology used by Mr. Candelaria to disallow Harry Allen Station site development costs, Mr. York testified that there were several serious errors. Mr. York explained that assigning only half of the costs of the electric interconnection to the current combustion turbine did not mean that the interconnecting facilities were built for two units. The costs of the interconnecting facilities would have been essentially the same had they been

[11] Mr. Gabour is proposing that all of the plant that is the subject of Mr. Candelaria's testimony be moved to plant held for future use. This would be contrary to the Commission's order in Docket No. 91-5055 that allowed NPC to accrue AFUDC on the site development costs retroactive to November 1985.

designed and built for one combustion turbine, rather than being designed for two combustion turbines and built for one combustion turbine, as was actually done. Key components necessary to connect two combustion turbines to the substation were not actually installed. The only additional costs included in the interconnection for the second combustion turbine were: (1) two switches which would allow for the installation (at an estimated costs of $22,000 for the two breakers); and, (2) a cable attached to the midpoint pole for the second generating unit (at an estimated cost of $5,000). Other than these two items, NPC incurred virtually no additional costs to design and construct the facilities to accommodate two combustion turbines rather than just one. Yet, Mr. Candelaria and Mr. Gabour arbitrarily allocated percent of the costs of the interconnecting facilities. The total additional costs incurred by NPC for designing the electric interconnecting facilities for two units was $27,000, compared to the $995,500 in gross plant disallowed by Mr. Candelaria and Mr. Gabour. Staff's approach, therefore, significantly overstates the portion of the substation attributable to a second unit. (Id. at 15-16.)

222. Mr. York also testified that Staff's Greenfield methodology significantly overstated the additional costs incurred for designing the generation station to accommodate multiple combustion turbines. NPC, in its response to Staff Data Request No. 183, provided the Greenfield estimate used in its analysis. The estimate provided by NPC, Mr. York testified, was a generic costs estimate for a single combustion turbine without any consideration of features necessary to install the combustion turbine at a particular site. Consequently, he claimed, the Greenfield estimate would have to be increased in order to take into consideration the additional site-specific costs that were incurred at the Harry Allen Station. Examples of items that would have to be included in the estimate are: (1) Tortoise Fees for the protection of an endangered species ($169,549); (2) purchase of water rights and associated property ($575,432); (3) capitalized property taxes ($355,957); (4) capitalized spare parts ($628,207); (5) training for operation and maintenance personnel ($464,974); and, (6) roadwork ($168,926). (Id. at 16-17.)

223. In addition, because the Harry Allen Station is in the desert, certain systems had to be modified to accommodate the high ambient temperatures that occur. Mr. Candelaria did not consider these additional costs. A reasonable estimate would require performing a component-by-component analysis of each system to determine the changes that would be required to tailor a single unit combustion turbine to the Harry Allen Station site. Because the estimate used by Mr. Candelaria did not consider the logistical, environmental, and technical

circumstances at the Harry Allen Station site, Mr. York claimed that Mr. Candelaria's analysis could not be used. (Id.)

224. Finally, Mr. York testified that the systems and components designed to accommodate additional generating units at Harry Allen Station have significant value in the market. However, NPC's ability to sell or lease the facility was restricted by Assembly Bill 369, passed by the 2001 Nevada Legislature, which said that an electric utility is prohibited from performing any act that would constitute disposal of a generating asset before July 1, 2003. Ordinarily, NPC would be free to sell or lease any property classified as Plant Held for Future Use. However, in this instance NPC cannot sell these generation assets. This creates a situation where NPC can neither earn a fair, just and reasonable return on its prudently incurred investment nor sell the property. This, he claimed, caused serious concern since this may amount to confiscation of utility property. (Id. at 18-19.)

225. On cross-examination by Staff, Mr. York agreed that the tap and gas pipeline at Kern River was sufficient to serve five 72 megawatt CT's[12] at Harry Allen Station. Mr. York explained that when NPC tapped into the Kern River pipeline it costs $1.8 million for the hot tap to the pipeline. So NPC sized the line in 1994 to provide up to eight CT's at Harry Allen Station. He explained the incremental costs for the tap to the larger pipeline were very small. (Tr. at p. 1047-1049.) Mr. York was questioned further about incremental costs of systems, and he agreed with Staff Counsel that a second evaporation pond cost $1.3 million. Mr. York stated the redundancy was necessary in case the first pond needed repairs. (Tr. at p. 1052-1054.) Mr. York also testified that NPC is currently planning to install peaking capacity at the Harry Allen Station site. (Tr. at p. 1059.)

Commission Discussion and Findings

226. Staff made a strong case that a significant portion of the Harry Allen Station site is not used. Given the size of the site at 6,000 plus acres, and the fact that only one CT is currently in operation there, it is clear that a majority of this location could not be considered used. (Tr. at p. 501.) Likewise, much of the infrastructure, which was sized for up to eight combustion turbines, clearly will not be used for several years. The Commission concurs with Staff's assertions on these points. Staff also identified a significant amount of substation investment (transmission/distribution facilities and equipment) that was oversized. Based on Staff's analysis, the Commission concurs that this investment is not currently used.

---

[12] Understood by the Commission to mean "combustion turbine".

227. On rebuttal, however, NPC was persuasive that Staff, in estimating the cost of a combustion turbine at an undeveloped ("Greenfield") site, underestimated the costs. The Commission believes that Staff should have considered additional expenses, such as "tortoise fees" and water rights, as well as others enumerated by NPC. Additionally, NPC's argument that there are virtually no additional costs associated with the facilities being designed for two combustion turbines, except for $27,000 related to breakers and a cable, is reasonable.

228. Consideration of these changes results in additional expenses (reduction to Staff's adjustment) of:

Interconnection Facilities	$ 965,500
less	$ 27,000
Change to Staff adjustment	$ 968,500
Other fees/costs	$2,360,045
Total change to Staff adjustment	$3,331,545

229. While the Commission agrees that planning for growth is an important consideration, it is simply not proper for ratepayers to be burdened with such excess investment. In this case, the Commission is not making any disallowances, but it is requiring plant that is not currently used be set aside until it becomes used for the benefit of ratepayers. With NPC’s current shortage of internal generating capacity, use of the existing Harry Allen Generating Station site to develop additional resources, either renewable or a combination of renewable/fossil fuel generating facilities, should be considered by NPC in order to reduce its dependence on purchased power. With additional development of this site, the problem of excess capacity will be diminished with a concomitant increase in NPC's authorized rate base.

230. In conclusion, the Commission finds that certain adjustments should not be recovered in this case, and that Staff's adjustments deferring part of the Harry Allen Generating Station site for future consideration are reasonable and appropriate. The Commission also finds that reductions to Staff’s adjustment as noted above (including changes to Accumulated Depreciation, Accumulated Deferred Income Tax, and Property Tax not specifically identified above) are appropriate.

W. Over-Accrued AFUDC

<u>Staff’s Position</u>

231. Staff’s witness, Mr. Gabour, recommended that an incorrect entry of $518,624 for AFUDC should be removed from rate base. (Exhibit 45 at p. 5.)

Commission Discussion and Findings

232. NPC agreed with Staff's AFUDC adjustment (NPC's Br. at p. 19, see I.A.5.2.) and therefore, the Commission finds that the removal of $518,624 from rate base for an incorrect entry to AFUDC is reasonable and approved.

X. Schedule N-3 Adjustment

Staff's Position

233. Staff's witness, Mr. Greedy, recommended that $6,966,000 be removed from the revenue requirement because NPC did not comport with the Commission's filing requirements for costs allocated from SPR to NPC. Moreover, Mr. Greedy claimed that NPC failed to make filings required by the Merger Compliance Order in Docket No. 98-7023 ("Merger Order") and did not comport with Exhibit 33 in Docket No. 98-7023. Mr. Greedy also asserted that NPC's new accounting system is not useful and NPC chose not to abide by a Commission approved stipulation. He stated that these allocated costs ($6,966,000) applied directly to management personnel responsible for assuring that NPC complies with Commission Orders. (Exhibit 54 at p. 21.)

NPC's Rebuttal Position

234. NPC's rebuttal witness, Ms. Simmons, testified that NPC tried to comply with Exhibit 33 ("Staff's model") in Docket 98-7023, but could not. Ms. Simmons continued to explain that from Mr. Greedy's own testimony in the that docket, Staff's model failed to produce information in the format Mr. Greedy had proposed in the merger docket (98-7023), and his model was "not available at this time because of computer errors….". Mr. Greedy promised that he would refile his model as soon as all computer errors and necessary reconciliations were resolved. Ms. Simmons's stated it was her knowledge and belief that Mr. Greedy was never able to produce the working model that was described in the Merger Order, and that such model has never been filed. Some of Ms. Simmons' staff worked independently with Mr. Greedy's model attempting to get his model to function. Her staff was unsuccessful however, because of circular references, missing files, and access problems with the computer model. From NPC's independent work, it has become clear that Mr. Greedy's proposed model would not produce the requested information in the format described in the Merger Order. When both NPC's and Mr. Greedy's best efforts failed to produce a working model, Ms. Simmons believed that the issue was moot. (Exhibit 84 at p. 9-10.)

235. Ms. Simmons testified that after reviewing Mr. Buck's testimony and his Attachment FCB-3 in the instant docket, it appeared to her that Staff had also given up on Staff's model and gone back to using the type of format previously used to present information and adjustments. Therefore, Ms. Simmons recommended that the Commission clarify that the accounting and reporting requirements from the Merger Order are no longer applicable and that any ongoing reporting requirements be addressed in the pending docket regarding the intercompany services agreements (Docket No. 01-10006), which is scheduled for hearing in June 2002. She also recommended that the Commission reject Mr. Greedy's proposed adjustment of $7 million in prudently incurred intercompany charges as unjust and unreasonable. (Id. at 10-12.)

236. Finally, Ms. Simmons testified that Schedule N-3 was provided in the manner and format previously accepted by the Commission. Schedule N-3 takes recorded information as shown in its official books and records and shows how those recorded costs are allocated to Nevada Electric and FERC jurisdictions. Schedule N-3 does not purport to represent shared services and costs. (Id. at 12-13.)

237. NPC's second rebuttal witness on this issue, Mr. Brown, testified that NPC's trial balance contained the balance at the beginning of the month for each of NPC's accounts, the net transaction activity that occurred during the month, and the balance at the end of the month. The general ledger contained the balance at the beginning of the month for each of NPC's accounts, adjusting journal entries, and a summary of the transaction activity for each feeder system (e.g. accounts payable, payroll, accounts receivable), and a balance at the end of the month. The general ledger and trial balance are neither unique nor unusual. Mr. Brown claimed it was unreasonable for Mr. Greedy to expect that the level of detail requested would reside in NPC's general ledger. Specific information related to labor, labor overheads, vouchers and all other costs affecting the account balance were contained in the subsidiary systems. (Exhibit 79 at p. 6-7.) Mr. Brown also testified that NPC's accounting system was no more complex than one should expect for a combination electric and gas utility with over 3,000 employees serving approximately one million customers in an extremely complex and challenging business environment. (Id. at 7.)

Commission Discussion and Findings

238. The Staff did not claim that NPC's intercompany costs were unreasonable or imprudent. Instead Staff requested that the Commission exclude these costs from rates because

NPC was not in compliance with Commission orders and NPC had not developed a useful accounting system. Staff also claimed that it had a limited amount of time to investigate filings from NPC and, as a result, it needed reliable data. (Staff Br. at p. 30.)

239. NPC presented evidence that showed compliance with the Commission's Orders relating to Schedule N-3 was impossible because the model NPC was ordered to utilize (Staff's model) did not work. In fact, not only did it not work, Staff was apparently not using it either. NPC also testified that its accounting system was not unique or unusual, but was appropriate for a utility of its size.

240. The Commission agrees with NPC's arguments that it could not comply with a previous Order regarding utilizing a Staff model that is not functional. And although the Commission sympathizes with Staff concerning receiving data in a presentable format, the Commission also realizes that accounting systems must be complex by their very nature to deal with the demands of the everyday business environment, and, as a result, information cannot always be neatly summarized on one page. Therefore, the Commission finds that Staff's schedule N-3 intercompany costs adjustment of $6,966,000 is unreasonable and not approved.

Y. Weather Normalization

<u>BCP's Position</u>

241. The BCP's witness, Mr. Brosch, testified that NPC's weather-normalized billing determinants should be revised from NPC's proposed 20-year average to a 15-year average to recognize the warming trend in Las Vegas. (Exhibit 66 at p. 21.)

242. On direct examination by his attorney, Mr. Brosch accepted Ms. Franklin's recalculation of his weather-normalized adjustment to account for the capacity shift impact. (Tr. at p. 997-998.)

<u>NPC's Rebuttal Position</u>

243. NPC's rebuttal witness, Ms. Franklin, testified that there are at least four reasons for rejecting Mr. Brosch's proposal to move to a 15-year definition of normal weather, at least for the purposes of this proceeding. First, the change was inconsistent with the "normal weather base" that was used by NPC in its recent Resource Plan proceeding (Docket No. 01-7016). In this Resource Plan proceeding, none of the parties, including BCP, objected to the using a 20-year normal weather base. Second, the 20-year definition of normal weather already reflects a 10-year reduction in the normal weather definition than has traditionally been used by NPC. As Mr. Brosch pointed out, NPC moved to the 20-year normal weather base definition in the 2001

Resource Plan proceeding due to its recognition of a warming trend in Las Vegas. Third, fundamental changes in weather normalization methodologies should not typically be made in an ex-post manner. If ex-post changes are permitted routinely, then the weather normalization results can be manipulated to yield outcomes that one or more parties find preferential. The fundamental purpose of weather normalization is to provide an objective means of adjusting loads to normal weather conditions. Significant changes in weather normalization should typically be made on a going-forward basis, and as infrequently as possible. Finally, as Mr. Brosch recognized in his testimony, reducing the period over which normal weather was defined creates the risk of introducing greater volatility into the definition of "normal weather." (Exhibit 66 at p. 24.) There was a difference between "weather normalization" and "weather forecasting." Shortening the time period over which normal weather was defined would push us more towards forecasting the weather instead of normalizing the effects of the weather. (Exhibit 81 at p. 13-15.)

Commission Discussion and Findings

244. On cross-examination by the BCP, Ms. Franklin stated that her concern with the use of the BCP's 15-year weather-normalized adjustment was that there should be consistency between the weather normalization and the annualized sales forecast, which uses a 20-year load forecast. (Tr. at p. 1099-1100.) The Commission agrees with Ms. Franklin, that in establishing the revenue requirement, there should be consistency between the annualized sales forecast used to determine the billing determinate and the weather normalization of the same sales. The Commission also agrees with NPC that its 20-year weather normalization already reflects a warming trend in Las Vegas, which was used and accepted in NPC's most recent Resource Plan in Docket No. 01-7016. The Commission finds that weather normalization changes should be made only after a study has been reasonably performed and only on a going-forward basis. Therefore, the Commission finds that NPC's 20-year weather normalization adjustment is reasonable and approved.

Z. Contributions in Aid of Construction ("CIAC") Adjustment

BCP's Position

245. The BCP's witness, Mr. Brosch, testified that its CIAC adjustment was required to properly annualize the income associated with amortization of income tax gross-up factor collections for CIAC and Customer Advances. William Branch testified for NPC that income credits are growing very rapidly, yet NPC had failed to annualize such amounts at Test Year end,

thereby understating ongoing amortization income as of September 2001. Mr. Brosch claimed that NPC Work Papers I-42.2 and I-42.3 indicated NPC's calculation of this income element, NPC simply differences the accumulated amortization accounts as of September 2001 versus September 2000, to include only the recorded per books amortization during the entire 12 month period. NPC's approach failed to account for growing balances in the gross-up accounts that are subject to monthly amortization. (Exhibit 66 at p. 28.)

Commission Discussion and Findings

246. NPC did not dispute the BCP's CIAC adjustment. Therefore, the Commission finds that the BCP's CIAC adjustment is reasonable and approves $1,148,000 in revenue amortization, which increases NPC's test year revenues. (See Exhibit 66 at Schedule C-2, line 9.)

AA. Annualize Late Charge Revenues

BCP's Position

247. The BCP's witness, Mr. Brosch, testified that NPC's omission of proposed new deferred energy accounting adjustment ("DEAA") revenues would dramatically increase the base of billed revenues subject to late charges. He recommended that this adjustment should be trued-up by the Commission, to remain consistent with the ordered outcome regarding DEAA revenues. (Exhibit 66 at p. 22.)

Commission Discussion and Findings

248. NPC agreed with the BCP's late charge revenues adjustment in Exhibit 81 at p. 18. Therefore, the Commission finds the BCP's annualized late charge revenues adjustment of $756,000 to be reasonable and approved. (See Exhibit 66 at Schedule C-3, line 10.)

BB. Transmission Revenue Credit

BCP's Position

249. The BCP's witness, Mr. Brosch, testified that his transmission revenue credit adjustment substituted recorded revenues for the 12 months ending September 2001, for the recorded amounts contained on Ms. Simmons's (Exhibit 24), with the difference multiplied by the applicable jurisdictional allocation factor. Updated amounts for the Certification Period for each transmission revenue sub-account were provided by NPC in its response to BCP Data Request 35-17. (Exhibit 66 at p. 31.) Mr. Brosch further testified that NPC provided information suggesting that consistent increases in transmission revenues, as well as transmission expenses, have occurred since 1998. According to the BCP, NPC stated, "NPC does not make

normalizing adjustments for these transactions since all transactions depend on third-party use of our system." (Id. at 32) Finally, Mr. Branch testified that NPC cited "Transmission projects like Crystal, Faulkner-Equestrian and Arden-Northwest" as contributing to the increased investment in transmission; increased transmission revenues available to offset these costs should be fully recognized in determining NPC's revenue requirement. (Id. at 33.)

NPC's Rebuttal Position

250. NPC's rebuttal witness, Ms. Simmons, testified that this adjustment was an attempt to predict future transmission revenues rather than using historical information available within the Test Period. (Exhibit 84 at p. 20.)

Commission Discussion and Findings

251. The Commission agrees with Mr. Brosch that the transmission revenue credit adjustment does not attempt to forecast future revenues but instead utilizes actual recorded data for the 12-months ended September 30, 2001. Therefore, the Commission finds the BCP's transmission revenue credit adjustment of $1,176,000 to be reasonable and approved. (See Exhibit 66 at Schedule C-4, line 14.)

CC. Payroll Adjustment-Executive Pay

BCP's Position

252. The BCP's witness, Mr. Brosch, testified that the Test Year included the costs of an extra executive position that should be eliminated. (Exhibit 66 at p. 116.)

Commission Discussion and Findings

253. NPC did not dispute the BCP's executive pay adjustment, and the Commission finds its removal from the test year to be reasonable. Therefore, the Commission accepts the BCP's adjustment to reduce expenses by $159,000. (See Exhibit 66 at Schedule C-7, line 5.)

DD. Coyote Springs Water Rights Amortization

BCP's Position

254. The BCP's witness, Mr. Brosch, testified that a full year's amortization of the gain on the sale of Coyote Springs Water Rights should be reflected in rates, rather than a reduced amount shown on line 14 of NPC's Schedule I-24 as "Unamortized." He argued this was necessary for several reasons: 1) the amortization treatment for this gain was approved in Docket No. 99-4005, which was not a rate case, such that no gain credits were flowed to customers as rate reductions at that time. The ratemaking amortization should commence with new rates from this Docket, when customers would first receive such benefits; 2) expiration of

amortization, if commenced in June 1998, would not occur until after the Certification Date, making NPC's proposal inconsistent with the appropriate cutoff for ratemaking at September 30, 2001; and, 3) other amortizations would also expire after September 30, 2001. If annualized in the manner of the Coyote Springs item, these other expiring amortizations would reduce amortization expenses in the test period.[13]

255. For these reasons, Mr. Brosch argued his Accounting Schedule C-14 was appropriate to restate the amortized gain at a full-annualized level. (Exhibit 66 at p. 129-130.)

<u>NPC's Rebuttal Position</u>

256. NPC's rebuttal witness, Ms. Simmons, testified that the BCP would have NPC increase revenues associated with Coyote Springs even though the amortization of the gain is accurately reflected in Schedule I-24. She claimed the BCP would have the Commission pretend that there is a bigger amount left to amortize just to reduce NPC's revenue requirement. As the adjustment stands in NPC's Schedule I-24, NPC will reduce revenue requirements more than necessary, since the recognition of the remaining gain of $487k will end within a few months but will continue to be accounted for in the overall revenue requirement until rates are reset in two more years. (Exhibit 84 at p. 20-21.)

<u>Commission Discussion and Findings</u>

257. The Commission agrees with Mr. Brosch. The Commission approved amortizing the Coyote Springs Water Rights gains at $1,116,000 per year for four years in Docket No. 99-4005, which resulted in no benefits flowing to ratepayers at the time, because the docket did not change rates. Therefore, the Commission finds that the BCP's Coyote Springs adjustment of $233,000 is reasonable and approved.

EE. Stock Issuance Expense

<u>BCP's Position</u>

258. The BCP's witness, Mr. Brosch, testified that NPC has not issued new common stock in the past seven-year period and does not expect to issue any new stock during the next ten years. Absent shorter intervals of re-occurrence, or other compelling justification for accelerated amortization, two years was too short a period to amortize the stock issuance costs. Mr. Brosch also testified that there are several reasons why a five-year period was generally reasonable for amortizing issuance costs for ratemaking purposes. First, he stated, simplicity

[13] For example, NPC's response to BCP Data Request 11-23 indicated expiring amortizations for Itron Field System $0.2M/ annually in November 2001 and Best Phase I System $0.2M in December 2001.

argues for a five-year period. Second, the amortization period employed for unusual, non-recurring deferred costs should be standardized for ease of administration, and the use of five years minimizes the need for carrying charges or rate base treatment often associated with longer amortization periods. (Exhibit 66 at p. 133-134.)

MGM's Position

259. MGM's witness, Mr. Garrett, recommended that NPC amortize these costs into rates over a four-year period. His proposal accomplished two important results: (1) it allowed NPC to recover all of its stock issuance expense, while (2) keeping current base tariff general rates as low as possible. This second objective was especially important to Mr. Garrett in light of the enormous rate increase NPC is asking ratepayers to bear for deferred energy costs and going forward Base Tariff Energy Rate ("BTER") expense. Mr. Garrett also testified that a four-year amortization synchronizes the recovery period with the statutory biennial rate case schedule in Nevada. A three or five year amortization period would expire in between rate cases. However, actual recovery would continue one additional year, until the next rate case. This could create an unintended over-recovery of these costs. (Exhibit 63 at p. 54-55.)

NPC's Rebuttal Position

260. NPC's Rebuttal witness, Ms. Simmons, stated that not a single party to this proceeding had argued that NPC was imprudent in incurring these expenses and issuing additional equity. In fact the record was clear that NPC had to issue additional equity in order to maintain its precarious credit ratings. She claimed that the Commission had ordered issuance expenses be amortized over two years, to match the anticipated "useful life" of the expense. Ms. Simmons also testified that it appeared that the intervenors proposed a longer amortization period in order to extend the recovery period of this prudently incurred expense beyond its useful life, with the hope of then being able to argue in the next general rate case that the continued amortization of this prudently incurred expense should be disallowed as an unusual item. (Exhibit 84 at p. 18-19.)

Commission Discussion and Findings

261. The Commission's policy has been to amortize securities' issuance expenses over a two-year period that matches their two-year shelf life. Therefore, the Commission finds that NPC's two-year amortization of the stock issuance expenses is the proper and reasonable way to handle these costs.

//

//

FF. Base Tariff General Rate ("BTGR") Capacity Shift

NCCEU's Position

262. NCCEU's witness, Mr. Page, testified that in AB 369, the Legislature mandated transferring the capacity component contained in the BTGR to the BTER. He claimed NPC restated its BTGR sales revenues by removing 12 months of those capacity payments in the amount of $151,407,000, yet NPC only credited BTER revenues, in their transfer to deferred energy accounts, by $100,681,000. To accurately reflect the impact on BTGR sales revenues during the test period, Mr. Page stated that the $50,726,000 amount not credited to BTER must be included in those BTGR sales revenues. (Exhibit 57 at p.13-14.)

NPC's Rebuttal Position

263. NPC's rebuttal witness, Ms. Franklin, testified that Mr. Page appeared to reduce revenue requirement by $25,363,000. She stated that he represented this amount to be one-half of the difference between 12 months of BTGR revenue related to capacity costs recovery which was being shifted to BTER ($151,407,000) and the amount of BTGR revenue related to capacity costs recovery which was credit to the deferred energy balancing accounts ($100,681,000). Both of these numbers resulted from the application of the same rate components to a level of billing determinates. Beyond that, she stated, they have nothing in common. (Exhibit 81 at p. 18-20.)

264. The revenue amount of $151,407,000 represented an estimate of "BTGR Shift" revenues that would be collected over a future 12-month period if NPC applied today's rates to the end of Certification Period customers and annualized weather-normalized billing determinates. It was referred to as present rate revenue. The amount of $100,681,000 was the total amount of "BTGR Shift" revenues that had been collected from March 2001 through September 2001 and credited to the deferred energy balancing account. It was referred to as recorded revenue. (Id.)

265. Pursuant to A.B 369, NPC re-implemented deferred energy accounting on March 1, 2001. Prior to March 1st, neither the fuel and purchased power expense nor the applicable revenue recovery was subject to balancing account treatment. At the end of February 2002, Nevada will have credited 12 months of BTGR shift revenue to deferred energy because it will have been on deferred energy accounting for a full year. Additionally, NPC will continue to calculate the BTGR shift revenue monthly and apply it to the deferred energy account until such time as the BTGR and the BTER are established in the current rate proceedings. (Id.)

Commission Discussion and Findings

266. The Commission finds that the evidence presented by NPC clearly supports NPC's calculation to reflect the shift of capacity revenues from the BTGR to the BTER in its general rate revenue requirement. The Commission finds that NPC's calculation of $151,407,000 represented a 12-month period, whereas the revenues of $100,681,000 reflected in Mr. Page's testimony only reflected the revenues collected between March 2001 and September 2001. Therefore, the Commission finds that NPC's calculation for the BTGR capacity shift is correct.

GG. Restructuring

NPC's Position

267. NPC's witness, Kathrynn Grosulak, testified that divestiture costs are properly recovered because they were expended in compliance with statutory and Commission mandates dating from 1997 through April 2001. With the passage A.B. 369 and A.B. 661, she stated that Nevada's restructuring model was profoundly altered. Expenditures made in furtherance of the old restructuring model are appropriately treated for ratemaking purposes as extraordinary and non-recurring expenses. She also testified that NPC's direct and allocated share of these restructuring-related costs totals $5.66 million. Applying an amortization period of four years, she stated, the impact of this request on annual revenue requirement was $1.42 million. (Exhibit 31 at p. 3.)

268. With one exception, Ms. Grosulak stated that NPC had limited its request to incremental costs for outside services. Incremental costs are out of pocket expenditures incurred to plan for, and implement, the Nevada Restructuring Model. The one exception was that NPC had sought recovery of internal labor costs (non-incremental) for one category of costs, an improvement work order for Customer Transaction Software. (Id. at 4.) Ms. Grosulak stated that NPC included internal labor costs that were charged to the work order for the Customer Transaction Software because generally accepted accounting principles ("GAAP") require that all costs associated with software development be capitalized. Both labor costs and incremental vouchers are therefore charged to capital work orders for computer and software projects. The internal labor costs associated with the development of the Customer Transaction Software ($670,000) are therefore currently held in a Construction Work in Progress or "CWIP" account.

If the Commission does not specifically allow recovery of these internal labor costs, they must be written off as a loss. (Id. at 4.)

269. Ms. Grosulak also explained that NPC had omitted the expenditures for consultants that were used to determine if it should enter the metering and energy business to maximize the asset value. Although some of these expenditures were necessary to meet NPC's statutory mandate to maximize asset value, she testified it would be difficult to segregate costs incurred to meet only the statutory requirement. Therefore, she stated that NPC erred on the side of minimizing the dollar impact of the request and eliminated all costs related to this effort. The eliminated costs amount to $640,000. (Id. at 6.)

270. On cross-examination by NCCEU, Ms. Grosulak stated that the costs associated with restructuring have been included in prior year financial returns. However, she stated the reason these costs were not set up as a regulatory asset previously was because GAAP required them to be written-off in the year the costs were incurred unless the Commission had specifically authorized them as a regulatory asset in an order. (Tr. at p. 443.) Therefore, NPC wanted to bring the costs forward into this case as a regulatory asset, because it believed that it should be compensated for implementing the Legislature's and the Commission's policies to restructure. (Tr. at p. 444.) Ms. Grosulak also stated that the restructuring of the electric utility industry would have benefited customers but for the Legislature abandoning it. (Tr. at p. 445.)

271. On cross-examination by Staff, Ms. Grosulak clarified that NPC had expensed NPC's restructuring costs in the year the expenses were incurred in compliance with GAAP. The only exception to this practice was the software costs for the Customer Transaction Software, which was capitalized. (Tr. at p. 453.) Ms. Grosulak agreed with Staff that the reason NPC expensed the restructuring costs in the year the costs were incurred was because the Commission ordered NPC to expense the restructuring costs in Docket No. 99-4005. (Tr. at p. 459.) Ms. Grosulak also agreed that the bulk of the costs for the restructuring occurred in the second half of 1999 and in 2000. (Tr. at p. 463.) Finally, Ms. Grosulak agreed that the Customer Transaction Software portion of the CIS system was still in development and would not be used and useful for a period of time. She also agreed it could be left in CWIP accruing AFUDC until it was determined if it would ever be useful. (Tr. at p. 472.)

272. On clarification by Policy Advisor Grant Siwinski, Ms. Grosulak stated that of the $1.42 million in restructuring costs NPC was requesting in the test year, $768,000 was actual expenses incurred in the test year. (Tr. at p. 474.)

//

//

MGM's Position

273. MGM's witness, Mr. Garrett, testified that Docket No. 99-4005 explicitly ordered NPC to write-off the costs of restructuring.[14] He also stated that merger savings were excess enough to allow recovery of the restructuring costs and, therefore, recommended that $646,000 of restructuring costs be removed from NPC's filing. (Exhibit 63 at p. 22-23.)

NCCEU's Position

274. NCCEU's witness, Terry Page, testified that $648,000 of past restructuring costs should not be allowed in rates because the costs were not incurred in the Test Year; divesture did not take place; and the effects of these costs have already been reflected in a prior year's financial returns. (Exhibit 57 at p. 18.)

BCP's Position

275. The BCP's witness, Mr. Brosch, testified that he supported the recovery of reasonable amounts of restructuring costs; incremental non-labor expenses incurred by NPC that directly relate to regulatory mandates associated with restructuring. However, NPC's proposal does include certain capitalized costs for the Customer Transaction Software, which Mr. Brosch recommended be eliminated because the costs were improperly attributed to restructuring. The Customer Transaction Software, according to Mr. Brosch, should be continued in CWIP until it was completed. (Exhibit 66 at p. 94-95.)

Staff's Position

276. Staff's witness, Mr. Galloway, testified and proposed expensing only costs incurred during the Test Period. NPC's inclusion of expenses from prior periods in the Test Year, he stated violated the matching principle. Those costs were recovered in prior period rates. Furthermore, the Commission ruled in Docket No. 99-4005 that NPC could not defer these costs because the balance of Senate Bill 438 would be lost. SB 438, he stated, granted NPC freedom from rate of return regulation as long as rates were not increased. Therefore, he recommended removing all out of period expenses from NPC's revenue requirement for restructuring costs. (Exhibit 49 at p. 6.)

277. Mr. Galloway also proposed that Customer Transaction Software be removed from rate base. He claimed NPC incurred these costs to develop processes for a customer's

---

[14] Docket Nos. 99-4005 and 99-4006, Paragraph 66 at p. 23.

competitive choice. Since customers do not have a choice of providers these costs are not used and useful. Therefore, he recommended they be removed from rate base. (Id. at 9.)

278. On cross-examination by NPC, Mr. Galloway agreed that NPC could seek recovery of the restructuring costs. (Tr. at p. 658.)

NPC's Rebuttal Position

279. NPC's rebuttal witness, Ms. Simmons, testified that Commission precedent and sound regulatory policy provide for the recovery of extraordinary costs that are incurred by the utility in order to comply with public policy mandates. Such costs, which are expended at the request of policy makers in the name of public policy, have in every instance been treated as "regulatory assets." In other words, the costs are accumulated and then amortized over a period of time, with a carrying charge. (Exhibit 84 at p. 14-15.)

Commission Discussion and Findings

280. The Commission agrees with NPC that prudently incurred restructuring costs that were expended in compliance with statutory and Commission mandates are appropriately recovered in rates for ratemaking purposes. That aside, the Commission believes that all prior year expenditures that were written-off because GAAP prohibited NPC from setting up a regulatory asset without a Commission order approving the regulatory asset shall not be recovered. These restructuring costs were expensed based on the Commission's directive in Docket No. 99-4005, and these costs have impacted prior period earnings. The Commission finds that only the current Test Year's restructuring costs of $768,000 are reasonable, and therefore approved.

281. The Commission also finds that the $2.063 million of Customer Transaction Software costs have been properly accounted for and should remain in CWIP accruing AFUDC until the system is developed and ready for Plant-In-Service. At that time, the Commission will determine whether the plant is used and useful and the costs can be recovered through rates.

HH. Merger Savings

NPC's Position

282. NPC sponsored two witnesses, Thomas Flaherty and Judy May, whom testified to savings achieved by the merger of NPC and SPPC ("the Companies").

283. Mr. Flaherty testified that he reviewed the before and after-merger electric O&M levels of the combined Companies, as well as specific results in selected areas of identified savings, to determine the electric O&M savings achieved as a result of the merger. His analysis

indicated that actual electric O&M expenses had been substantially reduced as a result of the merger and that initially identified costs savings were in fact captured overall; and that, even reflecting related growth and productivity factors, customers had benefited and will continue to benefit from lower costs levels. The level of electric O&M expense incurred by the merged company to meet customer requirements was identified, in his analysis, to be the following amounts less than the electric O&M costs which would had been incurred by the two stand-alone companies, absent the merger, during the annual periods year-ending December 31, 1998, December 31, 1999, and December 31, 2000: $3.7 million, $1.4 million and $37.3 million, respectively. (Exhibit 58 at p. 6.)

284. Mr. Flaherty also testified that merger savings initially began to be realized in 1998, although only to a very limited extent, through a hiring freeze that was implemented coincident with the April 1998 announcement date. This hiring freeze, he stated, resulted from merger planning and enabled required positions to be reduced as attrition occurred in anticipation of the combination and integration of the Companies. Savings from the hiring freeze continued to be realized in 1999, although the total savings estimated prior to the merger were slightly delayed due to a decision to synchronize many combination and re-staffing actions with the implementation of a new Enterprise Resource Planning system ("ERP"). Savings in 1999 were further offset by a pay equalization initiative instituted prior to year-end 1999. In 2000, merger savings levels began to reach steady state levels from initiatives begun in 1998 and 1999, and through the implementation of deferred initiatives (e.g. process redesign) that were pending ERP completion. He testified that given the continuing nature of most of the merger savings initiatives implemented through 2000, and additional savings initiatives under consideration by the Companies but not yet implemented, these savings could be expected to increase in subsequent years. (Id. at 7-8.)

285. Mr. Flaherty also reviewed actual results of the integration in selected areas (e.g., total and functional staffing), to determine how these results compared to initial expectations. In this area also, he stated, the Companies realized and in fact slightly exceeded the expected level of reductions. This is a key component of total merger savings as labor costs typically approximate 50% of total non-fuel O&M costs and are a principal determinant of the realization of operating efficiencies. (Id. at 8.)

286. Additionally, Mr. Flaherty reviewed the Companies' process for pursuing merger savings and found it to be comprehensive and consistent with common industry practice. He

benchmarked the merged Company against industry peer groups and found it generally to be a very low-cost provider, further validating that the Companies had both improved their relative peer group position as a result of the merger and had not left significant costs savings opportunities uncaptured. (Id. at 8-9.)

287. Ms. May testified that the savings generated by the merger have exceeded the costs generated by the merger. Consistent with the Commission's Order in PUCN Docket No. 98-7023, if merger savings allocable to the regulated utilities occurred, NPC should be allowed to amortize and recover the costs of the merger, including transaction and goodwill costs. To date, the merger has generated a total of $90 million in savings. The total cumulative annual amortization of costs generated by the merger is just $25.6 million. Based on her findings, she asserts that merger savings significantly exceed merger costs. Accordingly, NPC is seeking to amortize and recover its allocable share of merger costs. (Exhibit 59 at p. 2-3.)

288. Ms. May also testified that the total merger costs, which include transaction, transition and good will, are reflected on Schedule H-12, page 2. She stated that the breakdown of the total merger costs incurred at NPC and SPPC is $58,194,053, consisting of Transaction costs of $27,284,353 and Transition costs of $30,909,700. The severance and relocation costs as noted in Schedule H-12 had been included above in the transition costs total. Schedule H-12 also showed the total amount of goodwill generated by the merger ($326.282 million). Attached as Exhibit JVM-2, is Note 2 of the December 31, 2000 consolidated financial statement, which explained in detail the computation of goodwill. The prefiled testimony of witness John E. Brown further supported NPC's position with respect to the forty-year amortization period for recovery of these costs. (Id. at 3-4.)

BCP's Position

289. The BCP's witness, Mr. Brosch, testified that the retrospective analysis Ms. May had prepared was inappropriate, since the Commission should care only about whether merger savings in the pro-forma Test Period are sufficient to offset merger costs recovery. He stated that none of the analysis underlying the $90 million Ms. May claimed as merger savings was tied into Test Period values.

290. In addition, Mr. Brosch stated, Ms. May's analysis was flawed for several other reasons: 1) there had been no showing by NPC that the merger savings estimated by Ms. May could not have been achieved "but for" the merger. Indeed, non-merger variables impact NPC's actual incurred labor costs within the values she relied upon, including variables such as work

management efficiency, labor productivity levels, union negotiated wage rate changes and work rules, merit pay increases, employee turnover and position vacancies; 2) the calculated merger labor "savings" in Exhibit JVM-4 are derived entirely from application of "escalation" rates to prior period labor costs, with no accounting for productivity gains that are achievable without merging. If her inflation factors were simply offset with reasonable estimates of productivity improvement, no labor savings are evident; 3) the labor escalation rates applied to historical labor costs by Ms. May were derived from an "Employment Costs Index for Public Utilities", rather than an index of the specific union and non-union wage increase factors applicable to NPC's actual employees in Nevada. Actual wage rate growth for NPC's employees has been lower than the index values used by Ms. May; 4) labor costs should not be analyzed in isolation, since other resource inputs can be substituted for labor. New capital investment in technology can reduce labor requirements, and NPC has engaged in large new technology projects that did not require a merger to pursue. Other resource inputs such as contract labor can also produce indicated savings in labor, while overall costs increase. Contractor labor charges to non-production O&M have generally increased since the merger;[15] 5) labor Costs analyzed by Ms. May ignore variable and incentive compensation, which has become a larger component of total compensation for Company employees since the merger;[16] 6) the Commission had already found that Ms. May's labor savings from the hiring freeze in 1998 could possibly be attributed to productivity improvements or related to industry restructuring, rather than the merger;[17] 7) the non-labor savings amounts included in Ms. May's recapitulation Exhibit JVM-5 are based upon numerous unreliable estimates of costs changes, many of which could have been implemented without merging; 8) even though, by Ms. May's calculations, NPC has realized $97 million in merger savings through May 2001 to offset merger cost amortizations, NPC has yet to record any merger costs amortization on its books. Merger cost amortization should have commenced long ago, if NPC's believes its own estimates of merger savings commencing in 1998. (Exhibit 66 at p. 43-44.)

291. Mr. Brosch also testified that NPC did not show that the merger savings estimated by Ms. May could not have been achieved "but for" the merger. He went on to state that most of

[15] NPC Response to BCP Data Request 26-01 indicates outside service charges are generally higher after 1997 in all expense categories except Production O&M, where merger impacts were anticipated to be minor.

[16] NPC response to BCP Data Request 3-42 indicates increasing amounts of incentive compensation paid by NPC post merger.

[17] In paragraph 93 of its Interim Order in Docket No. 99-4005 the Commission rejected NPC's claim that the hiring freeze in 1998 and related labor costs reductions were merger savings.

the merger savings claimed by Ms. May represented changes in cost levels that might have been achievable without merging. He stated that NPC had managed its workforce and labor costs, as well as its new capital investment and non-labor expenses, in a manner that contained overall costs and avoided base rate increases for many years. This pattern was consistent with many other electric utilities over the past decade that have thrived in a low-inflation and low interest rate environment, introducing new technologies and automated systems to reduce labor requirements while improving customer service. Systems are commonplace today in the electric utility industry to automate customer call centers, facilities mapping and locating, energy management systems, field employee work management, customer database and billing functions, computer aided design and project management, as well as integrated financial planning and administration. He stated that this trend toward automation was not isolated to only the largest utilities or only to merging entities, but was widespread and had produced significant productivity gains in every electric utility he had observed. It was simply unrealistic, he stated, to assume that NPC could not or would not have acted consistently with the rest of the industry to reduce costs through technology and improved management systems. However, Ms. May's analysis, he stated, simply assumed that all containment of labor cost occurring since 1998 in Exhibit JVM-4 was a direct result of the merger and nothing else. (Id. at 44-45.)

292. Mr. Brosch testified, regarding Mr. Flaherty's analysis, that Exhibit TJF-2 did not accurately predict the amounts of O&M expenses that would have been incurred by NPC and SPPC "but for" the merger because of its reliance upon an unproven inflation escalation rate, productivity rates and customer growth factors that were based upon hypothesis and conjecture, rather than reliable, company-specific data. The problems, he argued, included: 1) an inflation index was employed by Mr. Flaherty to escalate the O&M expenses of NPC and SPPC after the 1997 base year, using the Consumer Price Index published by the U.S. Bureau of Labor Statistics.[18] Mr. Flaherty had developed no study or calculation of the changes in price levels for the market basket of goods and services actually purchased by the utilities to run their businesses. The CPI index he used was particularly inappropriate because it contains many consumer items such as food, clothing and housing costs that were not significant to utility operations; 2) a productivity factor was used to offset the CPI escalation described above. Rather than study and calculate the actual productivity achieved historically by NPC or SPPC, Mr. Flaherty relied upon Bureau of Labor Statistics average productivity factor values for the

[18] The escalation rates used were 1.6% for 1998, 2.7% for 1999 and 3.4% for 2000 (BCP 7-16)

entire electric utility industry, which reduced his "expected" O&M after the 1997 base year;[19] 3) the base year 1997 expenses were increased in all subsequent years based upon flawed estimates of expenses thought to increase directly as a result of adding new customers. The underlying analysis for these expense growth predictions was based upon linear regression calculations for data that does not vary directly with customers added. The regression calculations also double counted inflation impacts assumed to exist in the underlying data; and, 4) the analysis stopped with projections of theoretical expenses in 2000, with no effort to extend the analysis or reconcile the conclusions to the proposed test period expense levels. This was critically important, since merger costs should only be recovered to the extent of merger savings credited to customers within the test period used to set rates. The level of test period pro-forma O&M expenses proposed by NPC and SPPC in pending rate cases far exceeds expected combined O&M expenses in Mr. Flaherty's study, suggesting that no merger costs should be recovered. (Id. at 73-74.)

293. Mr. Brosch stated that the deferral of merger transaction and transition costs on the books was possible through reliance upon Statement of Financial Accounting ("SFAS") No. 71 Accounting for the Effects of Certain Types of Regulation, that allowed the creation of regulatory assets and liabilities when the future rate recoverability of such amounts was probable. Paragraph 10 of SFAS 71 provides that, "If a regulator excludes all or part of a cost from allowable costs and it is not probable that the cost will be included as an allowable cost in a future period, the cost cannot be expected to result in future revenue through the ratemaking process. Accordingly, the carrying amount of any related asset shall be reduced to the extent that the asset has been impaired." With this in mind, he testified, the approval of the BCP's position regarding merger costs would result in the write down of the carrying value of the merger-related regulatory assets. (Id. at 90.)

294. Mr. Brosch also stated, regarding goodwill, that a new pronouncement relaxed the previous accounting requirement that merger goodwill be amortized over a period no longer than 40 years. In its place substituted periodic "impairment testing" for goodwill and other intangible assets. He noted that SFAS 142 specified continuation of amortization accounting to the extent a regulator permitted all or a portion of goodwill to be amortized for ratemaking purposes. In this Docket, he stated, if goodwill amortization was not permitted for ratemaking purposes, NPC could cease amortization on the books. However, the required impairment testing under SFAS

---

[19] NPC responses to BCP Data Request 3-21 and 35-02.

142 may then reveal diminished value for the goodwill asset, unless the case was made that SPR was able to retain other merger-related financial benefits for its shareholders in amounts sufficient to not impair goodwill. (Id. at 91.)

MGM's Position

295. MGM's witness, Mr. Garrett, testified that all of the costs identified by NPC as merger-related transition and transaction costs should be disallowed for ratemaking purposes. He stated that in Docket No. 98-7023, NPC was ordered to absorb merger-related costs to the extent possible through merger-related savings. The Order in that docket, he suggested, clearly contemplated deferral of only those costs incurred in excess of savings achieved. Ms. May's work, he claimed, showed that NPC believed it achieved more than ample savings to absorb all of the merger-related costs. Consequently, no recovery of merger-related costs should be allowed in this case. Moreover, in Docket No. 99-4005, he claimed, NPC was explicitly ordered to write-off its deferred balances for merger-related costs. NPC's request to recover these costs in this docket was a direct violation of the Order in Docket No. 99-4005. (Exhibit 63 at p. 11-12.)

296. Mr. Garrett also testified that from the perspective of a sound ratemaking approach, these costs should have been deferred. After a merger, a utility was generally allowed to retain all of the savings that result from the merger, and was expected to bear all of the costs incurred to achieve the merger, until such time as new rates were established in the utility's next rate case proceeding. In that proceeding, rates would be set to capture -- now, for the benefit of ratepayers -- all the savings achieved as a result of the merger. At that time also, he stated, a Commission could review any acquisition adjustment associated with the merger to determine if any portion of the adjustment should be included in rates. The Commission could base a decision to include some portion of an acquisition premium in rates upon a finding that the synergies of the combination resulted in sufficient, quantifiable savings to justify an above-the-line amortization. In the case of NPC, he argued, NPC's own witnesses provided evidence that merger savings greatly outpaced merger costs over the last few years. In this situation, a deferral of merger costs for amortization in future rates should never be permitted. Mr. Garrett's adjustment to remove the effects of NPC's proposed recovery of these costs was as follows: an adjustment to remove merger costs from rate base of $34.501 million and an adjustment to remove merger costs from O&M of $3.450 million. (Id. at 12-13.)

297. Regarding goodwill, Mr. Garrett testified that NPC proposed to amortize the merger acquisition premium into rates over a period of forty years. The annual amortization requested by NPC was $4.727 million. In Mr. Garrett's opinion, this was the only issue related to merger costs that was legitimately before the Commission in previous dockets.[20] However, the ultimate regulatory disposition of the merger goodwill had not yet been determined. (Id. at 13.) He stated that the instant case marked the end of the interim period, and that the Commission must decide whether overall prospective savings[21] from the merger, i.e. lower costs levels going forward, exceeded prospective costs increases from the merger sufficient to justify the inclusion of some portion of the premium in rates. (Id. at 15.)

298. The approach taken by Ms. May and Mr. Flaherty, Mr. Garrett stated, which compared merger costs with alleged reductions in labor and non-labor O&M, was not dispositive on the issue; even if one accepted their analysis as accurate, because the analysis failed to consider the dramatic increases associated with fuel and purchased power costs in 2001. Obviously, fuel and purchased power costs increases have to be part of the calculation, because much of the run-up in these costs, according to NPC, resulted directly from NPC's efforts to divest of its generation assets. These issues were to be examined more closely in the Deferred Energy Case. But for the Commission to determine that overall costs are lower as a result of the merger, he argued, it would have to conclude that virtually all of the fuel and purchased power costs increases resulted solely from higher market prices for these commodities, and not from indecision by NPC related to divesture. NPC cannot, on the one hand, he argued, blame divestiture for fuel and purchased power increases in the Deferred Energy Case, and, on the other hand, claim that overall costs were lower as a result of the merger in this docket. (Id. at 15-16.)

299. Mr. Garrett recommended removing the goodwill amortization of $4.727 million from the revenue requirement.

NCCEU's Position

[20] The Order issued in Docket No. 98-7023 instructed NPC to both enjoy the savings and bear all of the costs of the merger during the three-year interim period. To the extent merger costs outpaced merger savings during this period; a deferral of merger costs was permitted. Since savings instead out paced costs, as reported by Ms. May, no deferral was needed. In Docket No. 99-4005, the Commission again instructed NPC to bear both the costs and the savings related to the merger during the period of the rate freeze, and explicitly withdrew the costs-deferral mechanism set up in Docket No. 98-7023 for the deferral of excess merger-related costs. As noted, no mechanism was necessary, since savings, according to Ms. May, were sufficient to cover all of the costs.

[21] Here Mr. Garrett was concerned with prospective savings that can be passed on to ratepayers. Savings that occurred in the interim period were retained by shareholders and have no bearing on this analysis. Savings in the interim period are only relevant to show that no deferral of transition and transaction costs was necessary, in light of the savings that occurred over that period.

300. NCCEU's witness, Mr. Page, testified that there were two reasons not to recommend an increase in revenues for merger costs. First, he claimed, there were no benefits to NCCEU's members, all customers of NPC, as referred to in the Stipulation approved by the Commission in their Order dated March 10, 2000 in Docket No. 98-7023 ("Stipulation"). By that standard alone, he stated these merger expenses did not meet the Commission's requirements to be allowed as a revenue adjustment. (Exhibit 57 at p. 16.) Second, he claimed these costs were not experienced in the Test Year and, therefore, should not be reflected in NPC's revenue requirement. (Id. at 16.)

301. Mr. Page also stated that NCCEU expected benefits from the merger that did not materialize. Specifically, Paragraph No. 50 in the Commission's Order adopting the Stipulation, says; "The Joint Applicants, Staff and the UCA believe the Stipulation is in the public interest; will allow parties who wish to enter the market sooner, rather than later, to do so, and will allow the parties and the Commission to focus on other market issues that need to be resolved; and will avoid expensive and time-consuming litigation." Those benefits for NCCEU members, he argued, clearly had not been available. NPC's request to recover merger costs by relying on the Stipulation as the basis for that recovery, without taking into account the benefits that were supposed to result from the Stipulation and did not, was blatantly unfair to the members of the NCCEU. (Id. at 17.)

302. Finally, Mr. Page testified that there was a rate stabilization perspective. The two NPC cases before the Commission created the potential for this to be the largest rate increase ever ordered into bills of NPC's customers. In Mr. Page's opinion, it was absolutely inappropriate to add to the size of those increases for items that occurred outside the Test Year. (Id. at 17.)

303. On cross-examination by NPC, Mr. Page agreed that when he referred to a "stipulation" in his testimony regarding merger costs, that stipulation had absolutely nothing to do with merger costs and savings. (Tr. at p. 851.) Mr. Page also agreed that his rate stabilization program would allow NPC to apply for the merger costs in 24 months because he had not made any determination that any of the costs were imprudent. (Tr. at p. 852.) In fact, he stated he was recommending that the Commission defer the decision on these costs until a later date. In order for these costs to remain on NPC's books and records versus being written off, Mr. Page suggested that the Commission's order could contain strong language that stated the merger costs had not been examined for prudence, as the prudence of the costs would be considered at a later

date. (Tr. at p. 855.) He also agreed that the Commission's order should include language that recovery of the merger costs would be considered at a later date when rates are more stable and customers may be able to pay for them. Finally, Mr. Page stated that if the merger costs earned a carrying charge, it would send a stronger signal to the financial community of the Commission's actions to allow recovery of prudently incurred costs in the future. (Tr. at p. 856.)

Staff's Position

304. Staff's witness, Mr. Greedy, testified that the Commission should exclude merger costs from NPC's revenue requirement used for setting just and reasonable rates because: 1) timeline requirements have not been met; 2) merger savings have not occurred; 3) merger accounting was not correct; 4) NPC had inappropriately claimed merger savings; and 5) NPC's claimed merger savings were ethereal.

305. Regarding the Commission's merger costs recovery mechanism, Mr. Greedy testified that rates were frozen for three years beginning December 31, 1999, and for the calendar years 2000, 2001 and 2002. He also claimed that NPC could only file a general rate case after the three-year rate freeze ended. He stated that if savings from the merger were sufficient, then prudent and eligible transaction, transition and perhaps, goodwill might be included in rates.[22] Thus, according to the Merger Order, Mr. Greedy claimed that the test period for measuring experienced merger savings was no sooner than the twelve months ending December 31, 2003 [SIC], which was the last year of the three-year period for any merger savings to accrue and become fixed. (Exhibit 54 at p. 2-3.)

306. Based on his interpretation of the Merger Order, Mr. Greedy recommended that merger costs and divesture costs be excluded from rates in this filing because test periods in this docket do not meet the requirements for merger costs recovery. In the instant docket, the Test Period, the twelve months ending May 2001, and the Certification Period, twelve months ending September 2001, were all within the Commission's merger costs recovery mechanism's three-year period for shareholders to benefit from merger savings and costs. (Id. at 7.)

307. Mr. Greedy also testified that the Certification Period in this docket, the twelve months ending September 2001, was thirty-three months after the test period in Docket No. 99-4005. While this was not the complete three-year period set in the Merger Order, Mr. Greedy claimed that some cost reductions should have occurred at NPC. However, the fact that NPC

---

[22] Merger Compliance Order, pages 104-106 in Docket No. 98-7023.

was now requesting a revenue increase of $28 million, despite the occurrence of claimed merger savings, clearly demonstrated that merger savings had not occurred. (Id. at 9.)

308. Regarding accounting for merger costs, Mr. Greedy testified that the first three years of experienced merger costs and savings were not computed in conformance with the Merger Order. The merger completion date for accounting purposes was August 1, 1999. (Exhibit 59, Atch JVM-2 at page 1.) Consequently, he stated, costs incurred after August 1, 1999 and through the end of the three-year period must be removed from NPC's recovery of proposed merger costs in Schedules H-12 and I-12. (Id. at 10.)

309. Regarding NPC's claimed merger savings, Mr. Greedy testified that NPC's witnesses, Ms. May and Mr. Flaherty, simply created hypothetical costs that were higher than experienced costs and claimed the difference was a merger savings. Further, the merger savings came about in the year 2000 when the budget was reduced by $30 million. This completely ignored, he argued, the question: "If the two companies operated separately in 2000, would it not be reasonable for the two companies to independently reduce their budgets?"

310. Staff also stated that Ms. May's basic premise was to escalate payroll values from prior to the merger, compare those values to experienced payroll values, add the individual differences and produce a cumulative value for merger savings. This naturally would yield a larger number than the merger costs, especially if the beginning payroll value was even slightly higher than any subsequent payroll value. Ms. May's analysis, he claimed, did not resolve the basic conundrum; NPC began with a $28 million surplus of revenue over costs, but NPC was now requesting a rate increase. Mr. Greedy also stated, however, that the Commission's merger costs recovery mechanism required actual costs to decrease before merger costs could be included in the customers' rates. Ms. May's testimony, he claimed, did not meet this test set in the Merger Order. (Id. at 14.)

311. Regarding Mr. Flaherty's claimed merger savings, Mr. Greedy stated that at first blush Mr. Flaherty's analysis appeared to be reasonable, but all it did was compute an inflated value for hypothetical operations and maintenance expenses against which his adjusted operations and maintenance costs could be compared. Applying an inflation factor to a before merger value allowed for a specious comparison to actual results. There was no reason, he stated, why the two companies could not restrain their costs independently and have the same results as the merged companies. The same logic applies for any perceived efficiency gains. However, if the combined companies were truly more efficient, one would expect to find that the

total operations and maintenance expense would at least not increase and hopefully would decrease. Therefore, he claimed, the total expense for ratemaking had increased, not decreased, and NPC was requesting a revenue increase when merger savings were in place. NPC's request for a revenue increase, he argued, flew in the face of NPC's assertion of existing merger savings. (Id.)

312. Mr. Greedy also stated that Mr. Flaherty used calendar year comparisons, while ignoring the rate making process underlying the Commission's merger costs recovery mechanism. Mr. Flaherty's calendar year 2000 test year, according to Mr. Greedy, only coincided with the Test Year in this filing for the period June through December. Mr. Flaherty's hypothesis ignored the possibility of costs increasing after the Test Period in this filing. (Id. at 16-17.)

313. On cross-examination by NCCEU, Mr. Greedy stated that the first test year NPC would be eligible for merger costs recovery under the merger order was 2003. (Tr. at p. 753.) He also stated that NPC never asked the Commission to modify its order on merger costs or savings. (Tr. at p. 754.)

314. On cross-examination by NPC, Mr. Greedy again stated that it was his testimony that the three-year period before NPC was eligible to recover merger costs was the calendar years 2000, 2001 and 2002. (Tr. at p. 781.) Mr. Greedy also stated that even though new rates were being set with this case, which violated the three-year hiatus of the merger order, he did not believe there was a violation of the three-year rule for merger costs because NPC had not demonstrated any merger savings. (Tr. at p. 784-785.)

NPC's Rebuttal Position

315. NPC's rebuttal witnesses, Ms. May and Mr. Flaherty, testified that the merger costs should be allowed in rates. Ms. May testified that other witnesses had proposed that no merger costs recovery be approved in this Docket. She stated that the Commission should reject these contentions since NPC had followed the directives in the Merger Order in PUCN Docket No. 98-7023. With the exception of a small number of items that NPC had acknowledged, the intervenors had failed to raise any reasonable contentions that individual merger expenses were imprudently incurred and should not be recovered. Furthermore, she claimed, that while the Merger Order was not specific as to how the merger savings should be tracked and calculated, NPC had made compelling arguments to prove that the merger savings had been achieved and that there should be merger costs recovery. (Exhibit 75 at p. 2.)

316. Mr. Flaherty testified that Intervenor witnesses Mr. Brosch and Mr. Greedy were incorrect in their assertions that the evidence presented by himself and Ms. May did not clearly establish that the Companies had realized merger costs savings sufficient to cover merger related costs. He had shown, even with conservative adjustments made, that the experience of the Companies had been to substantially exceed those costs and to clearly reduce costs below the level that would have occurred absent the merger. He stated that this couldn't be controverted. Further, he claimed that the illustrative points made by Messrs. Brosch and Greedy were incorrect, unfounded or misstated and could not be relied upon. (Exhibit 77 at p. 3.)

317. Mr. Flaherty stated that his testimony highlighted the errors in Mr. Brosch's assumptions and resulting conclusions about his merger savings calculations by elaborating on why the methodology deployed in his analysis was appropriate and produced reasonable results, including a discussion of the differences between his approach and that used by Ms. May. Mr. Flaherty also discussed how the combination of these two analyses fulfilled the requirements for demonstration of synergy attainment established in the Merger Order. He also discussed the validity of the assumptions and variables used within his analysis and addressed the spurious, and often incorrect, assertions made by Messrs. Brosch and Greedy. (Id.)

Commission Discussion and Findings

318. A number of questions have been raised as to whether, or to what extent, merger savings may have been realized by NPC. Questions were also raised regarding the extent any deferred costs should be recovered by NPC. Based on the testimony, the Commission is concerned about the level of savings that NPC may anticipate on a going-forward basis. However, the Commission will not rule on the issue at this time.

319. Although assertions were made by NPC that merger savings have reached a "steady-state", the Commission is not convinced that enough time has elapsed since the merger for this to occur, given all of the disruptions that have taken place in the electric industry in the West. Additionally, as noted by Mr. Greedy, the test period in this docket does not meet the requirements for merger cost recovery. The Compliance Order in Docket 98-7023 specifically stated that the Applicants shall file a general rate case at the end of the three-year period. (Order at 104.) As Mr. Greedy indicated, this period extends through the end of 2002. Accordingly, the first test year for including potentially eligible costs is the year ending December 31, 2002.

320. The Commission will also not make any determination as to the prudence of any of the transaction, transition or goodwill costs at this time. Instead, such costs are to be

maintained in a deferred account until NPC files a general rate case with a test year ending on or after December 31, 2002. Since NPC has testified that merger savings exceed merger costs, a carrying charge on the balance of these costs is not justified.

321. In summary, the Commission finds that NPC may file a general rate case application that includes a request for recovery of potentially eligible merger related costs if the test year is on or after December 31, 2002. At that time, the Commission will take testimony and rule on all issues surrounding these costs.

II. Divesture Costs

NPC's Position

322. NPC's witness, Mr. Rice, testified that SPPC and NPC filed two separate and distinct divesture plan proposals with the Commission before gaining final approval to proceed with the auction. The two-staged auction process was completed early in the fall of 2000. Over the next several weeks, seven final sales agreements were negotiated with seven winning bidders on seven-generation bundles. NPC filed the first of those agreements, related to NPC's interest in the Mohave Units, with the Commission and obtained final approval to proceed with the sale. The companies negotiated a staggered filing schedule for the remaining agreements with the Commission's Staff and BCP, and began making those filings. In January 2001, the California Legislature enacted A.B. 6X, which barred SPPC from selling its generation assets through 2006. In April 2001, the Nevada Legislature enacted A.B. 369, which prohibits NPC and SPPC from divesting their generation facilities. (Exhibit 33 at p. 6-7.)

323. Mr. Rice testified that NPC's direct and allocated share of divesture-related expenditures was $16.518 million. NPC was seeking to recover these costs over four years, rather than the customary three-year amortization period used for this type of expenditure. Thus the annual impact on revenue requirement for this category of costs was $4.1 million. (Id. at 9.)

BCP's Position

324. The BCP's witness, Mr. Brosch, testified that incremental non-labor costs incurred by NPC that directly related to statutory and regulatory mandates associated with divesture should be allowed in rates, over a reasonable period of time. However, NPC's proposal improperly includes certain labor and labor overhead costs that were not incremental to normal, ongoing costs and expenses. In addition, he argued, the proposed amortization period was too rapid in light of the nature of the costs. (Exhibit 66 at p. 99.)

325. Mr. Brosch also testified that a 10-year amortization period was more appropriate than NPC proposed 4-year period because he wanted to moderate the rate impact on customers. (Id. at 100.)

NCCEU's Position

326. NCCEU's witness, Mr. Page, testified that he had three reasons to exclude divestiture costs from rates: 1) these costs were not incurred in the Test Year; 2) divesture did not take place; and 3) the effects of these costs had already been reflected in a prior year's financial returns.

327. On cross-examination by NPC, Mr. Page agreed that he had not made a determination that the divesture costs were imprudent. (Tr. at p. 852.) Mr. Page also stated that, in his opinion, the Commission could defer these costs as a regulatory asset with carrying costs for recovery at a later time to avoid a write-off. (Tr. at p. 855.)

MGM's Position

328. MGM's witness, Mr. Garrett, testified that divesture costs were merger related costs. He also testified that as merger related costs, they should have been recovered out of merger savings. Therefore, NPC's deferral of divesture costs was inappropriate and he recommended removing $11.963 million from the rate base and $3.988 million from O&M. (Exhibit 63 at p. 19-20.)

Staff's Position

329. Staff's witness, Mr. Greedy, testified that divesture costs were merger costs because the Joint Applicants in Docket No. 98-7023 explicitly proposed selling their power plants as part of the merger. In that Docket, the Joint Applicants clearly would not have sold their power plants without the merger. Prior to the time of Docket No. 98-7023, there was no legislative or administrative demand to sell power plants. Thus, divesture costs, according to Mr. Greedy, were also merger costs. (Exhibit 54 at p. 17.)

330. Mr. Greedy also testified that the divesture costs should have been booked in Account 186 as a deferred debit. Inclusion of the divesture costs in Account 186 would allow the applicant to track costs for final disposition. These costs, he stated, should be "below the line" and should be an offset to any gain on the sale of generation assets. (Id. at 19.)

331. Finally, Mr. Greedy recommended that the Commission exclude divestiture costs from the revenue requirement in this filing and allow NPC to decide if today's divestiture costs should be held for possible future costs recovery. (Id. at 20.)

332. On cross-examination by USAN, Mr. Greedy stated that the divesture costs should be considered merger costs because NPC clearly made divestiture part of the merger conditions. Mr. Greedy also testified that none of the divestiture costs should be included in rates at this time. (Tr. at p. 755.)

333. On cross-examination by NPC, Mr. Greedy agreed that in 1998 when the Commission, Staff and NPC talked about divestiture costs being netted against the proceeds from the sale of the plants. (Tr. at p. 786-787.)

<u>NPC's Rebuttal Position</u>

334. NPC's rebuttal witness, Mr. Rice, testified that even though the merger and divestiture of generation facilities were proceeding at roughly the same time, the two transactions were entirely different. The costs incurred for divestiture were to be subtracted from the proceeds of the sales of the power plants. At no place in the Merger Order, according to Mr. Rice, was it stated that these costs would be accounted for as merger related costs. To account for the costs related to the potential sale of assets as merger costs goes against the Federal Energy Regulatory Commission policies for accounting for electric plant purchased or sold. (Exhibit 83 at p. 3.)

335. Mr. Rice also testified that Mr. Page failed to realize that these costs were what had been considered "unusual and non-recurring" in prior Commission orders. Consistent with proper ratemaking treatment and precedence, he claimed, the Commission had segregated these types of costs and required that they be amortized over a three-year period. Mr. Page was correct that divestiture did not take place; however, the halt of divestiture was not caused by NPC's imprudence. Rather divestiture was halted by the Nevada Legislature, which required all divestiture activities to be stopped until at least mid-2003. Mr. Page misstated, he argued, the fact that the divestiture costs had been reflected in the costs recorded in prior years. These costs were recorded as an asset and to date had not been included in any income statement report. Disallowance of these costs could trigger an immediate write off. (<u>Id.</u> at 4.)

336. Mr. Rice testified that Mr. Brosch had requested that internal labor and labor-related costs be excluded from the requested amortization, and the balance spread out over ten years. In his prefiled direct testimony, Mr. Brosch stated that, "Incremental non-labor costs incurred by NPC that directly relate to statutory and regulatory mandates associated with divestiture should be allowed rate recovery, over a reasonable period of time." (Exhibit 66 at p. 100.) Mr. Brosch indicated that the reason for his proposed disallowance of labor costs was due

to the fact that no new employees were hired by NPC to specifically deal with divestiture, thus no incremental labor costs were incurred. Mr. Rice stated, however, that NPC determined that retaining employees who had taken the merger severance package would be more efficient than hiring new employees. A number of employees were asked to remain until the divestiture was complete, including the project manager. Therefore, these labor costs were truly incremental to the process. (Id. at 4-5.)

337. Finally, Mr. Rice testified that, as mentioned previously, the Commission had in the past required a three-year amortization of similar "unusual and non-recurring" costs. In fact, on page four of his direct testimony, Mr. Galloway said that the Commission had approved a three-year amortization of other unusual items. There was no precedent for a ten-year amortization of these costs. NPC had proposed to lessen the rate increase to its customers by using a four-year amortization period, rather than a three-year period. (Id. at 5.)

Commission Discussion and Findings

338. Mr. Greedy for Staff and Mr. Garrett for MGM stated that the divestiture costs should be considered merger costs because NPC agreed to sell its generation plants as part of the Merger Compliance Order. If the divestiture costs are merger costs, then, as Mr. Garrett testified, they should be recovered out of the merger related savings, which he claims have already occurred. The Commission does not agree with the arguments that divestiture costs should be considered merger costs. The Merger Compliance Order in Docket 98-7023 clearly discusses merger and divestiture as two completely different topics. Therefore, the Commission finds that divestiture costs are not to be considered part of merger costs.

339. The Commission agrees with the BCP and NPC that divestiture costs expended in response to regulatory mandates associated with divestiture should be recovered if they are prudently incurred. The Commission believes that recovery of the divestiture costs should be netted against the proceeds from the sale of the plants, as suggested by Mr. Greedy in his cross-examination.

340. The Commission disagrees with the BCP that labor and labor overhead associated with retaining employees should be disallowed since the labor was not incremental. The Commission agrees with NPC that retaining employees, who had accepted the merger severance package, to work on the divestiture was efficient. The Commission also agrees with NPC that if it had to contract for these employees to do this work, the new personnel would have been incremental and allowable as divestiture costs. Therefore, the Commission finds that NPC's

labor and labor overheads contained in the divestiture costs are appropriate; the prudence of the costs will be determined when the plants are sold.

341. Finally, the Commission agrees with Mr. Greedy and Mr. Page that the divestiture costs should be deferred as a regulatory asset until the plants are sold, or some other mechanism is proposed to allow recovery of the costs. The Commission shall allow carrying costs on the deferred asset. While it is difficult to imagine that any divestiture could be found in the public interest given NPC's severe shortage of internal generation capacity, the issue is not one that can be resolved until at least mid-2003. Circumstances at that time may differ from today's circumstances, and/or some alternative may be available to NPC. The Commission anticipates that these costs shall be fully recoverable at some point. Therefore, the Commission finds that the divestiture costs shall be deferred as a regulatory asset, with a carrying cost. If the generation plants are sold, the divestiture costs shall be netted against the proceeds of the sales of the plants.

IV. Depreciation Study

A. Adoption of Rates

NPC's Position

342. Although NPC's depreciation rates were last modified in 1992 (Docket No. 91-5032), NPC's witness Mr. Ruelle stated that due to the hardship caused by recent rate increases and prospective rate increases, NPC has limited its depreciation request in this proceeding to change only those rates that are "most outdated and egregious", and therefore defer both consideration and implementation of the remainder of the depreciation study until the next general rate proceeding. NPC identified only one account requiring modification in this proceeding, computer equipment that is currently being depreciated over twenty years and for which NPC is proposing a seven-year life. By limiting its request in this proceeding to implementing the depreciation rate change to computer equipment, NPC is seeking to increase depreciation expense by $5.8 million in lieu of approximately $18 million. (Exhibit 1, Statement L and Schedule G-3, and Exhibit 27 at p. 48-49.)

Staff's Position

343. While Staff is not endorsing the underlying calculations or methodologies used by NPC to derive the depreciation rates, Staff recommends the Commission adopt and implement NPC's proposed depreciation rates as modified by Staff. (Exhibit 91 at p. 6.)

344. Staff clarified that it did not evaluate the methodologies used by NPC to derive its proposed depreciation rates; Staff accepted the rates solely on the basis that the methodologies used were those accepted by the Commission in Docket No. 99-4006. (Tr. at p. 1238.)

345. In addition, Staff noted that the significant depreciation issue is the intergenerational allocation of depreciation expense. However, due to future depreciation studies being performed it is not "exactly a critical issue what particular rates are in any given time." (Tr. at p. 1238-1239.)

346. During Commission questioning, Staff revised its early position by acknowledging that intergenerational distribution of depreciation expense is an important issue. Further, Staff concurred that if customers were paying significantly higher rates today than a couple of years ago, the Commission and its staff should look very closely at depreciation rates. (Tr. at p. 1240-1241.)

NCCEU's Position

347. Witness for NCCEU, Mr. Page, recommended that the Commission not change the computer equipment depreciation rate as requested by NPC on the basis that the following could occur in a future proceeding: other parties may recommend a reduction in depreciation rates for other accounts; NPC might mitigate rate increases; and, time will be allowed to establish a reserve for future computer purchases. (Exhibit 57 at p. 19-20.)

BCP's Position

348. The BCP stated that after correcting for several deficiencies in NPC's depreciation study, which are discussed individually later in this order, the resulting revised depreciation rates should be implemented, as the current rates are excessive. (Exhibit 92 at p. 22-23.)

NPC's Rebuttal Position

349. NPC's Rebuttal witness, Donald Roff, stated that, depending on circumstances, a piecemeal approach for implementing depreciation rates is not necessarily unreasonable. (Exhibit 93 at p. 19.)

350. Further, Mr. Roff quantified the affects of the both BCP's and Staff's proposed depreciation adjustments. (Exhibit 93, Atchs DSR-1R and DSR-2R.)

//

//

Commission Discussion and Findings

351. Staff did not provide any rationale in support of its recommendation that the Commission not grant NPC's request to implement only a change in the computer equipment depreciation rate.

352. NCCEU's recommendation to deny NPC's proposed increase in computer equipment depreciation rates ignores the fact that NPC, by its very request, has sought to mitigate the impact associated with the rate increases before this Commission. Further, the recommendation ignores the fact that depreciation expense recovers the cost of existing equipment; it does not establish a "reserve" for future acquisitions.

353. The BCP's recommendation to implement its revised depreciation rates is predicated upon its opinion that the current rates are excessive. As discussed later in this Order, the Commission is not accepting all of the BCP's proposed adjustments. Based upon the plant balances contained in the Depreciation Study (See Statement A), the Commission estimates that the potential total $18 million increase in depreciation expense would be reduced by $9.1 million. The estimated adjustment in depreciation expense is lower than the $12.2 million NPC seeks to forgo in this proceeding.

354. The Commission finds that NPC's request to implement a revised depreciation rate for only computer equipment, and use the 1992 depreciation rates approved in Docket No. 91-5032 for the remaining accounts, is reasonable and should be granted. The depreciation rate to be applied is discussed later in this Order.

B. Steam Production Unit Life Span / Retirement Date

NPC's Position

355. NPC witness Mr. York stated that the current projected retirement dates used to develop the proposed depreciation rates are appropriate. Regarding the steam production units, NPC's re-evaluation of the retirement dates were as follows:

- Mohave Units 1 and 2; NPC is seeking resource plan approval for improvements to extend the units operations from 2006 to 2026.
- Clark Units 1 – 3, 9, and 10; due to divestiture and accommodation to the proposed unit buyers NPC has not developed a plan to extend these units lives from 2006 and 2007, respectively.

- Current environmental regulations and reduction in the quality of western coal may preclude Reid Gardner Units 1 and 2 from operating beyond 2005 and 2008. (Exhibit 90 at p. 2-4.)

356. During the hearing, Mr. York noted that in NPC's recent resource plan (Docket No. 01-7016) the Commission authorized NPC to pursue studying the possibility of extending the Mohave Generation Station's life beyond 2006. Mr. York noted that the Mohave Generation Station owners' decision is expected by the end of the year. (Tr. at p. 1222-1223.)

357. Further, Mr. York noted that while the Reid Gardner Units 1 and 2 are approaching their current projected 40-year life mechanically, the units could operate beyond the forecasted retirement date. However, as with the Clark Units, insufficient time has passed since divestiture termination to study the potential life extension for these units. NPC will submit the results of its studies in a future resource plan. NPC's next resource plan is due in 2003. (Tr. at p. 1223-1225.)

<u>BCP's Position</u>

358. BCP witness Michael Majoros, Jr., contended that NPC's proposed life span for steam production units is too short and that NPC is unable to support its proposed life spans for these facilities. Mr. Majoros recommended the steam production units be afforded a 55 year life span in lieu of NPC's average 42 years. Mr. Majoros' recommendation is based upon a study conducted by his firm, "National Study of U.S. Steam Generating Units Lives – 50 MW and Greater." Mr. Majoros' firm's study disclosed that the average service lives for steam production units of 50 MW of capacity or greater have been increasing for several years; this coincides with the wide-spread introduction of life extension projects. Further, Mr. Majoros relied upon an on-site visit by an associate, which revealed no physical evidence supporting a life span of less than 55 years. (Exhibit 92 at p. 12-13 and Atch MJM-2.)

359. Mr. Majoros stated that NPC does not have the studies, plans, or forecasts specified in the NARUC Depreciation Practice Manual to support its proposed steam production unit life spans. The BCP witness stated that the NPC life spans were those developed in 1983 for resource planning purposes, and this conclusion was derived from NPC's response to BCP Data Request 2-01. Further, Mr. York's testimony indicates that NPC recognizes that the life spans for several of its steam production units are too short. (<u>Id.</u> at 10-12 and Atch MJM-2 at p. 4-6.)

360. Mr. Majoros stated that the retirement date is the most important factor in determining the depreciation rate in the "life span" method used by NPC to develop steam

production plant depreciation rates, as it is this date, in conjunction with the original installation date, which is used to develop the units' depreciable lives. (Id. at 8-11)

NPC's Rebuttal Position

361. In rebuttal, Donald Roff for NPC stated that BCP's blanket reliance upon a national study does not comply with NARUC's Public Utilities Depreciation Practices manual; as the BCP's methodology does not consider all the factors necessary in the development of a retirement date. For example, the BCP assigned an additional 15 years to Reid Gardner Units without considering environmental requirements or fuel supply. Mr. Roff contended that Mr. Majoros did not attempt to link his firm's study results to NPC's circumstances. Further, using the information contained in Mr. Majoros' study, Mr. Roff calculated a weighted average service life of 38.5 years, which is significantly different from BCP's proposed 55 years. (Exhibit 93 at p. 7-10 and Atch DSR-3R.)

Commission Discussion and Findings

362. BCP's witness Mr. Majoros' recommendation was based primarily upon a study conducted by his firm, "National Study of U.S. Steam Generating Units Lives – 50 MW and Greater". This study found that the increase in the average 50MW or greater steam production unit's service life coincided with wide spread application of life extension project. BCP's blanket applicability of a 55-year service life for NPC's steam units did not reflect NPC specific circumstances. For example, BCP presumed the Mohave Units would be retiring in the year 2026 rather than 2006, even though NPC and the other owners have yet to complete the life extension studies for this generating station.

363. Although relying upon the 1983 forecasted retirement dates, NPC recognized that the mechanical lives for various steam units may exceed the current forecasted retirement date. NPC asserted that due to the divestiture termination it had insufficient time to complete life extension economic studies for various steam generation facilities (i.e., Clark Units 1, 2, 3, 9, and 10 and Reid Gardner Units 1 and 2). NPC stated that the Mohave Generation life expansion studies should be completed by year-end (2002), and that it will file any steam generation life extension plans in a resource plan. The next NPC resource plan is due to be filed in 2003.

364. NPC did not rebut BCP's contention that the retirement date used in the development of the steam production plant depreciation rates is the most important component of the calculation.

365. The Commission finds that NPC's proposed steam generation plant lives should be used in this depreciation study.

366. Considering the importance of the forecasted retirement date in the development of steam production plant depreciation rates and the potential extension of the operating lives for various steam production units in a resource plan, the Commission further finds that NPC should file a new depreciation study in conjunction with its next general rate application, which is expected to be filed in 2003 in accordance with NRS 704.110(3).

C. Production Plant Interim Additions

NPC's Position

367. NPC witness Mr. Roff stated that it is appropriate to include interim additions (activity that occurs between the original in service date and the final retirement date) in the development of depreciation rates, for without these additions the estimated production plant retirement date cannot be obtained. Further, Mr. Roff argued that the elimination of interim additions results in an over-allocation of depreciation expense to current customers as it necessitates the adoption of shorter remaining lives for depreciation rate purposes. (Exhibit 89 at p. 10, 14 and 17.)

368. While acknowledging that the Commission rejected NPC's inclusion of interim additions in its 1991 general rate case (Docket No. 91-5032), the last NPC general rate case to include a depreciation study, NPC witness Mr. Roff asserted that the Commission's logic was contrary to a strict adherence to the historical test year concept, as the Commission accepted the inclusion of future interim retirements. Further, Mr. Roff stated that the depreciation study filed in this proceeding was performed in the same manner as the study filed in conjunction with NPC's 1999 Compliance Filing in Docket No. 99-4006, and the Commission accepted the study therein. However, Mr. Roff acknowledged that the purpose of the 1999 proceeding was to establish rates for unbundled distribution service. (Exhibit 89 at p. 16-17.)

369. NPC calculated future interim retirements based upon a ratio of past retirements to the sum of depreciable balances. Future interim additions were estimated by developing a ratio of historical additions to historical retirements, and by applying this ratio to the estimated future retirements. (Exhibit 88, Statement B at p. 9.)

BCP's Position

370. BCP Witness Mr. Majoros, Jr., stated that it is inappropriate to include estimated future additions in the calculation of depreciation rates. Mr. Majoros noted that the NARUC

depreciation manual, while acknowledging the appropriateness of including future interim retirements in the development of depreciation rates, states interim additions are to be excluded until they occur. In addition, the BCP argued that inclusion of future interim additions in depreciation rates requires existing customers to pay for future plant additions. (Exhibit 92 at p. 15-17.)

NPC's Rebuttal Position

371. NPC rebuttal witness, Mr. Roff, reiterated NPC's assertion that the elimination of future interim additions necessitates shorter service lives for production plant and that the Commission accepted the NPC's methodology in Docket No. 99-4006. Further, Mr. Roff cited his disagreement with NARUC's Public Utilities Depreciation Practices manual recommendation concerning the exclusion of future additions. (Exhibit 93 at p. 15-17.)

Commission Discussion and Findings

372. Inclusion of the interim additions indirectly includes the recovery of costs associated with future plant additions from current customers. Inclusion of future interim retirements and the exclusion of future interim additions do not violate the historical test year concept. Future interim retirements recover the cost of existing production plant components over their useful lives, while future interim additions are intended to incorporate future plant expenditures in the depreciation process. The NARUC depreciation manual excludes interim additions from the determination of depreciation rates until the addition is experienced.

373. The Commission finds that, in this instance, NPC's inclusion of interim additions in the development of production plant depreciation rates is inappropriate and should be removed from the development of depreciation rates for these plant accounts.

D. Cost of Removal Escalation

NPC's Position

374. Since NPC does not have any historical experience with the removal of coal and oil/gas fired generation plants, NPC's witness Mr. Roff used a collection of site-specific demolition cost estimates obtained from other utilities to derive an average unit cost per Kw. Using this average rate, Mr. Roff developed the cost of removal for each production plant. Subsequent to the development of each production plant demolition cost, Mr. Roff escalated the estimated costs three percent annually. Mr. Roff asserted that the escalation is necessary to determine the amount that will be spent to retire the plant and is consistent with accrual accounting, which allocates these amounts over the life of the asset. (Exhibit 89 at p. 19.)

375. Upon cross-examination by the BCP, Mr. Roff stated that NPC had not performed any formal studies about dismantling any of NPC's production plants, and that therefore it was assumed NPC would demolish the facilities. Mr. Roff's assumption was based upon representations made by NPC. (Tr. at p. 1216-1217.)

376. During clarification questioning by the Commission, Mr. Roff stated that the escalation rate was founded upon his experience and judgment, which included consideration for general inflation and local conditions. (Tr. at p. 1221.)

BCP's Position

377. BCP witness Mr. Majoros recommended that the Commission not accept NPC's escalation of production plant cost of removal, as it would require the ratepayers to pay a future inflation rate on an uncertain event; namely, if the plant will actually be dismantled. While it is assumed that the plant would be removed, BCP stated that NPC is uncertain that it has any legal obligation to dismantle these plants. Further, an associate of the BCP witness performed a survey of steam generating units with 50MW or greater capacities that have been retired since 1982. While the survey indicated 148 steam units meet the criteria, the present status of only 81 units could be determined. Of the 81 units identified, 68 units, or 84 percent, were retired in place and 13 units were dismantled. Of this 13, only five units' sites were returned to "Greenfield" condition. (Exhibit 92 at p. 17-19 and Atch MJM-8.)

NPC's Rebuttal Position

378. NPC's rebuttal witness, Mr. Roff, made three assertions:

- it is self evident that dismantling costs as expressed in current dollars need to be escalated to reflect the cost at the time of retirement;
- accrual accounting requires the recovery of the decommissioning costs over the life of the asset; and
- the Commission adopted the same methodology in Docket No. 99-4006.

(Exhibit 93 at p. 11.)

Commission Discussion and Findings

379. While no Party to this part of the proceeding disagreed that the costs of removal should be recovered over the life of the production plant, the BCP raised a concern as to the appropriate amount to be recovered. NPC has not performed any formal studies as to the dismantling of its production plant. BCP also did not provide any NPC specific information indicating whether NPC would dismantle its production plants.

380. NPC did not provide sufficient support for the application of a three percent escalation rate to the cost of removal. Due to the lack of justification for the proposed escalation rate and the lack of formal dismantling studies, the Commission finds that NPC will not apply an escalation factor in the development of production plant cost of removal.

E. Net Salvage Value for Services (Account No. 369)

BCP's Position

381. BCP's witness, Mr. Majoros, recommended a zero percent net salvage value for Services, Account No. 369. Mr. Majoros stated that NPC's proposed negative salvage value ratio of 125% is based upon a study of only $98,058 in total retirements that occurred during 1986 through 1998, which represents only 0.08 percent of the current Services Account balance of $111,818,770. BCP's witness contended that this data is "much too thin to rely upon." Further, the BCP's net salvage analysis indicates a significantly more reduced level of negative net salvage than that used by NPC. (Exhibit 92 at p. 20-21 and Atch MJM-10.)

382. Further, BCP's witness recommended that NPC be required to change its accounting to charge the entire cost of replacing Services to new construction, rather than classifying the cost as a cost of removal. As justification for its proposal, BCP's witness stated that NPC replaces all retired Services and that some Services are a result of conversion from overhead to underground cable. (Id. at 21.)

NPC's Rebuttal Position

383. NPC's rebuttal witness, Mr. Roff, stated that BCP's proposed capitalization of cost of removal, as a component of new construction does not comply with the FERC's uniform system of accounts, which was adopted by the Commission. Further, Mr. Roff asserted that BCP's witness did not attempt to understand the sources of data that were used in the development of its net salvage value. For example, the BCP ignored the fact that in 1998 the MGM Grand Hotel purchased its Service facilities, thus providing a significant inflow of net salvage proceeds; it is likely this event will not occur again. Excluding this transaction from the BCP's distribution plant net salvage analysis indicates declining salvage amounts. (Exhibit 93 at p. 12-14.)

Commission Discussion and Findings

384. BCP's proposed capitalization of the Services, Account No. 369, cost of removal as a component of new construction violates the uniform system of accounts and would effectively charge new customers the cost incurred to provide existing customers service. BCP's

witness apparently did not review the data used in it its distribution net salvage analysis for potential non-recurring events.

385. The Commission finds NPC's recommended negative 125% net salvage value to be reasonable and approved.

F. Net Salvage Value for Computer Equipment (Account No. 391.2)

Staff's Position

386. Staff Witness Herbert Thompson recommended a three percent salvage value for computer equipment rather than the zero percent proposed by NPC. Staff cites the following publication which recommends a five percent net salvage for general computer equipment, "Salvage and Cost of Removal for LEC Investments" by Ray Hodges, p. 14-15. Further, Staff asserted that unlike other equipment, computer equipment would be virtually costless to remove. (Exhibit 91 at p. 3-4.)

387. Acceptance of Staff's proposal would result in a computer equipment depreciation rate of 21.58 percent rather than NPC's proposed 22.40 percent. (Id. at Atch HGT-2.)

NPC's Rebuttal Position

388. NPC's rebuttal witness, Mr. Roff, does not have a "real quarrel" with Staff's proposed three percent net salvage value. (Exhibit 93 at p. 2.)

Commission Discussion and Findings

389. The Commission finds that the positive net salvage value of three percent for the development of the computer equipment depreciation rate to be reasonable and approved. The Commission also finds that this results in the Staff depreciation rate of 21.58 percent, thereby reducing depreciation expense for revenue requirement purposes by $149,000.

G. Rate Base Adjustments

Staff's Position

390. Staff recommended that the depreciation rates approved in this proceeding reflect the following: (1) Staff's adjustment to accumulated depreciation for NPC's non-implementation of the depreciation rates authorized in Docket No. 99-4006; and, (2) Staff's proposed adjustment to plant accounts. Due to the depreciation study being based upon the December 31, 2000 date, plant information for all of Staff's adjustments would need to be adjusted to this date. (Exhibit 91 at p. 5-6.)

//

//

Commission Discussion and Findings

391. Staff did not provide the estimated effect of its proposed depreciation rates, nor the information to derive the estimated impact. Further, it is doubtful that the impact would be sufficient to offset NPC's requested postponement to increase annual depreciation expense by $12.2 million, or the estimated $3.1 million after Commission adjustment. The Commission finds that Staff's recommendation in this section should be denied.

V. Cost of Service

A. Unbundling Study

BCP's Position

392. BCP Witness Mr. Marcus proposed three adjustments be made to NPC's unbundling study:

- Regulatory expenses, other than mill assessment (Account 928), should be allocated to the various functions based upon revenues; these costs are incurred for all functions. NPC had directly assigned these expenses to the distribution function.
- Utility restructuring expenses recorded in Account 930 and the rate base item should be allocated to the various functions based upon revenues. While the purpose behind restructuring was to develop a competitive generation market, changes were required in all three functions. NPC had directly assigned these expenses and rate base to the distribution function.
- The Las Vegas Franchise prepayment account, a rate base item, should be allocated to all functions based on revenues, which is the methodology used by NPC to allocate the franchise fee expense. (Exhibit 114 at p. 40-41.)

NPC's Rebuttal Position

393. NPC's rebuttal witness, Laura Lipparelli stated that NPC concurred in part and disagreed in part with the BCP proposals. NPC proposed the following modifications to its unbundling study:

- Allocate the regulatory expenses, other than mill assessment, using the allocation ratio number five in lieu of revenues. This allocation ratio (which consists of operation and maintenance expenses less several types of expenses (i.e. fuel, purchased power, deferred energy, and administrative and general expenses)), has been used to unbundled several administrative and general expense accounts and operation and maintenance expense accounts.
- NPC disagreed with BCP's restructuring cost allocation proposal "because these costs were incurred to benefit those customers that were most likely to leave NPC's system for

alternative generation sources." If these costs were allocated to the three functions then departing customers would not pay their share of restructuring costs.

- NPC concurred with BCP's Las Vegas Franchise prepayment adjustment. (Exhibit 117 at p. 27-28.)

394. In addition to the aforementioned proposals, NPC proposed a correction to allocation ratio number five for an error NPC detected. The correction increases the distribution revenue requirement by $13 million, and decreases generation and transmission functions by $12 million and $1 million, respectively. (Id. at 29.)

Commission Discussion and Findings

395. No Party involved in this portion of the proceeding challenged NPC's correction of an error in the calculation allocation ratio number five. Therefore, the Commission finds that the correction of the allocation ratio number five is reasonable and will be accepted as it increases the accuracy of the study.

396. The Commission finds that NPC's proposed allocation of the regulatory expenses, other than the mill assessment, in the same manner afforded other administrative and general expenses is reasonable, and therefore approved. The Commission also finds NPC's direct assignment of restructuring costs to the distribution function reasonable, as it insures that any entity leaving the system would pay a share of these costs.

397. NPC concurred with the BCP's proposal to allocate the Las Vegas Franchise prepayment account to the functions based upon revenues. The Commission finds this reasonable and therefore approved.

398. NPC argued that restructuring should be allocated as a distribution cost to all customer classes. Mr. Marcus pointed out that this could create an uneven burden on residential customers. The Commission believes both arguments are persuasive. Under the current provisions of NRS 704B, only customers with a one-megawatt load can take advantage of restructuring, and then only under a narrow set of circumstances. Nevada law, as well as the national restructuring experience to date, make it clear that the benefits of restructuring to residential and other small commercial customer groups is theoretical, or at best, indirect. Therefore, the Commission finds that all restructuring costs allowable in this Order shall be apportioned to the distribution function revenue requirement for only the following customer classes: LGS-3, LGS-X, LGS-WP-3, LGS-X-WP, SL, MSL-P, and MSL-C. However, due to the eligible governmental entity requirement being one-megawatt in the entire service area rather

than one location, and the marginal cost study not containing information on a subclass basis, the listed classes may not encompass all the potential governmental customers.

B. Reconciliation Marginal Cost Study to Embedded Revenue Requirement

NPC's Position

399. NPC performed its marginal cost of service study on a functional basis. (Exhibit 96 at p. 3, Exhibit 101 at Statement O at p. 1, and Exhibit 102 at Statement O at p. 1.)

DOE's Position

400. Dr. Dale Swan, witness for DOE, recommended that the Commission continue to apply the "Full-on-Full" method in the reconciliation of the marginal cost study results to the embedded revenue requirement, rather than a functional reconciliation. A "Full-on-Full" marginal cost reconciliation determines the embedded revenue requirement responsibilities of a customer class, general rate, and BTER revenues in total, whereas a functional marginal cost reconciliation determines the total embedded revenue requirement of a customer class by function. Dr. Swan asserted that even though use of marginal costs provides for some time of use weighting, the application of the functional approach makes the marginal cost study akin to an embedded cost of service study, as similar usage allocations would be applied. (Exhibit 109 at p. 9-12.)

401. Dr. Swan stated that the accumulation of the Deferred Energy Accounting Adjustment ("DEAA") Balance of nearly $1 billion dollars occurred as a result of planning errors in NPC's attempt to achieve both acceptable system reliability and minimization of the system's economic costs on a whole. Due to the nature and magnitude of the costs, Dr. Swan argued that these costs should be included in the revenue reconciliation process and allocated proportionally to a customer classes' contribution to the system's total costs. This can only occur when the "Full-on-Full" reconciliation methodology is used. (Id. at 12-14.)

402. During cross-examination by Staff, Dr. Swan stated that implementation of DOE's recommendations, concerning the revenue reconciliation and the no rate rebalancing adjustment, would significantly increase single residential customer class rates as outlined in Attachment DES-3 to his testimony. (Tr. at p. 1464 and Exhibit 109 at Atch DES-3.)

403. During clarification questioning by the Commission, Dr. Swan stated that it does not necessarily follow that one can not perform a "Full-on-Full" marginal cost to embedded revenue requirement reconciliation, and develop a functional distribution charge. (Tr. at p. 1465-1466.)

BCP's Position

404. BCP stated that it is reasonable to reconcile marginal costs to the embedded revenue requirement on a functional basis in the unbundled paradigm that exists today (certain customers are allowed to choose alternative providers). (Exhibit 114 at p. 38.)

405. BCP recommended that the sum of generation costs included in both the BTGR and BTER be reconciled to the sum of the marginal energy and capacity costs; otherwise, an embedded rather than a marginal cost allocation occurs. BCP asserted that NPC's method assigns capacity to the BTGR and energy to the BTER because the embedded costs are assigned to these two rates. (Id. at 12-39.)

Staff's Position

406. Staff 's witness, Anne-Marie Bellard, concluded that NPC's marginal cost of service study is an appropriate method of allocating costs between customer classes for this proceeding. (Exhibit 106 at p. 5.)

NPC's Rebuttal Position

407. NPC's rebuttal witness, Ms. Lipparelli, stated that although NPC believes a fully functionalized reconciliation is appropriate, BCP's proposed methodology combining generation and energy for reconciliation purposes would be reasonable. However, Ms. Lipparelli stated it is still important to have the marginal energy costs coincide with the type of capacity being used as marginal capacity. NPC contended BCP did not derive the appropriate marginal energy costs. (Exhibit 117 at p. 20-22 and Tr. at p. 1606.)

408. During Commission questioning regarding Dr Swan's proposal, Ms. Lipparelli stated that in the era of limited access to the open market it is more appropriate to use a functional reconciliation in the derivation of an unbundled distribution rate. (Tr. at p. 1605-1606.)

Commission Discussion and Findings

409. A "Full-on-Full" marginal cost reconciliation determines a customer classes' embedded revenue requirement responsibilities, general rate, and BTER revenues in total, whereas a functional marginal cost reconciliation determines a customer classes' total embedded revenue requirement by function. As evidenced by the functional customer class responsibilities set forth in NPC's Certification Period Statement O, the customer classes' cost responsibility varies, potentially significantly, with the function. A functional marginal cost reconciliation

incorporates these differences. NRS 704B.300 through 704B.350 require the development of unbundled rates for those entities that are allowed to leave the system.

410. The Commission believes that NPC's proposed fully functionalized marginal cost study more accurately derives a customer classes' cost contribution in total and by function. Therefore, the Commission finds that NPC's proposed fully functionalized marginal cost study is reasonable and approved.

C. Marginal Generation Costs

NPC's Position

411. NPC's witness, Charles Pottey, stated that marginal generation capacity costs represent those costs associated with the generation necessary to serve the incremental load plus reserves. In compliance with the Commission's previous directive in Docket No. 92-1067, NPC used the recent Resource Plan filed in July 2001 (Docket No. 01-7016) as the basis for selecting the least cost marginal resource. That Resource Plan relied upon firm purchase power as the near term energy source. Therefore, NPC used the purchased power capacity costs associated with the contracts filed with the resource plan to develop the marginal generation capacity cost. Since the purchased power contracts' energy prices were limited to the cost of fuel, additional adjustments were made to reclassify fuel related costs incorporated in the purchase capacity contract costs to the energy component (e.g., variable operation and maintenance expenses). (Exhibit 95 at p. 2-4.)

412. Mr. Pottey further stated that the marginal generation capacity costs were allocated to the various customer classes by using the generation costs of each hour, based upon loss of load probability, and then allocating to each customer class based upon weighted customer load and time of use factors. These load weighted cost factors were rescaled to the annualized sales. (Id. at 5-7.)

Staff's Position

413. Staff concluded that NPC's marginal cost of service study is an appropriate method for allocating costs between customer classes in this proceeding. (Exhibit 106 at p. 5.)

BCP's Position

414. The BCP's witness William Marcus asserted that NPC double counted marginal generation capacity costs. NPC's marginal energy costs include all capacity costs, except for the transmission related component. The spot market energy prices that under-pin NPC's marginal

energy costs are for firm energy. Firm energy includes capacity or reliability costs. (Exhibit 114 at p. 3-8.)

415. Alternatively, Mr. Marcus stated if the Commission determines marginal generation costs are appropriate, the marginal capacity costs should be that of a combustion turbine. A combustion turbine is the type of unit that would be constructed to be a peaking resource, not a combined cycle unit. The additional capital costs associated with a combined cycle unit acquire more than reliability, they also acquire lower cost energy. (Id. at 3, 6, 7, 10, and 11.)

NPC's Rebuttal Position

416. NPC's rebuttal witness, Ms. Lipparelli, stated that NPC's marginal energy costs were based on energy only and did not include capacity. NPC utilized various surveys to develop its marginal cost with the intention of excluding capacity costs. While some of the fixed contracts included in NPC's study contained a capacity component, those fixed contracts were classified as take-or-pay contracts thereby prohibiting those contracts from being considered as marginal energy. (Exhibit 117 at p. 4-5 and Tr. at p. 1586.)

417. Further, Ms. Lipparelli asserted that short-term energy markets represent the excess energy a supplier has available, and, depending on market conditions, the supply may not recover capacity costs. For example, according to the Down Jones index for Mead/Marketplace during January 15, 2002, through February 13, 2002, the price for on-peak power was \$2.83/mWh more than non-firm power. The price for off-peak power was \$1.05/mWh than non-firm power. The price differentials are not adequate to recover cost of generation capacity. (Id. at 5-6.)

418. Regarding the BCP combustion turbine alternative, NPC reiterated its compliance with a previous Commission directive in Docket No. 92-1067, to rely upon the most recent resource plan to develop marginal generation costs. The July 2001 Resource Plan stated that NPC would be meeting near term supply requirements with firm purchase power contracts. These contracts are the basis for NPC's marginal generation cost. (Id. at 6-7.)

419. Ms. Lipparelli asserted that if the Commission were to accept BCP's combustion turbine recommendation, the marginal energy cost needs to be adjusted to reflect the use of this less efficient generation unit. The BCP's alternative proposal develops marginal generation capacity costs using the capital costs associated with a combustion turbine but using the energy costs of a combined cycle unit. (Id. at 6-7.)

420. In addition, Ms. Lipparelli stated that a change in the marginal generation capacity costs would not affect a customer class marginal cost allocation ratio as the loss of load probability would not change. Further, use of a functional marginal cost reconciliation to embedded revenue requirements prevents any change in marginal generation costs from affecting the revenue requirement allocation of a customer class. (Id. at 8 and Atch LIL-REB-1.)

421. During cross-examination by the BCP, Ms. Lipparelli concurred with the BCP that one-part firm contracts do contain a capacity component, and that component may be difficult to identify. NPC, although not perfect, made every effort to eliminate capacity costs in the derivation of its marginal energy cost. If the capacity cost was identifiable it was removed, either on a contract-by-contract basis or based upon the differentiation between firm and non-firm energy. The difference between spot firm and non-firm is very small, so in some areas where NPC was unable to identify capacity its impact would be limited. (Tr. at p. 1583-1588.)

Commission Discussion and Findings

422. While acknowledging that it is difficult to identify capacity costs contained in one-part firm spot market contracts, NPC asserted that it had made every effort to exclude capacity costs from its marginal energy cost calculations. Further, NPC asserted that any amount included should be insignificant.

423. The BCP alleged that NPC's marginal generation costs double counted the capacity costs since capacity costs are included in NPC's marginal energy costs. However, the BCP did not provide any analysis indicating that NPC's marginal energy costs indeed include capacity costs or the amount of such costs.

424. The BCP did not disagree with NPC's assertion that NPC complied with a previous Commission directive to utilize the resource plan as the basis for the development of marginal generation capacity costs. The BCP also did not disagree with NPC that the combined cycle unit is the resource supporting the purchased power contracts contained in the 2001 Resource Plan.

425. Based upon the aforementioned, it is clear that NPC's proposed marginal generation costs were formulated following Commission directive. Therefore, the Commission finds that NPC's proposed marginal generation costs are reasonable and approved.

D. Marginal Energy Costs

NPC's Position

426. NPC witness Mr. Pottey stated that the marginal energy costs were developed using PROMOD. The particular PROMOD case used was consistent with the 2001 Resource Plan update, with the exception of updating for current market conditions. Additionally, Mr. Pottey noted that the short-term firm purchases were replaced with hourly market price forecasts for calendar year 2002. The resulting costs were increased for various types of expenses (e.g., variable operation and maintenance) and rate base items (e.g., fuel inventory costs) to arrive at the marginal cost of energy for a generator. To reflect the costs at the meter, the total marginal energy costs were adjusted to include losses. (Exhibit 95 at p. 11.)

427. During cross-examination by NCCEU's counsel, Mr. Pottey stated that an "across the board" reduction in energy prices would have no impact upon rates since the price profile would not change. The price profile is the relationship of on-peak prices to off-peak prices. However, Mr. Pottey expressed his opinion that if a PROMOD were run using today's price profile a minor cost shift may occur. (Tr. at p. 1301-1302.) While acknowledging that he has no documentation supporting his opinion, Mr. Pottey stated that there was no indication that the current price profile was necessarily any better than the one used. (Tr. at p. 1302.)

DOE's Position

428. Dr. Swan recommended that NPC update its marginal energy costs to reflect a revised market price forecast based upon current market conditions, and file this update with its rebuttal testimony. Dr. Swan stated that NPC's marginal energy costs were developed using a NPC market power price forecast prepared in July of 2001, and that these forecasted energy prices are approximately double the current market prices. In absence of this updated forecast, Dr. Swan proposed to reduce NPC's marginal energy costs by thirty percent. Dr. Swan observed that his proposed reduction is consistent with a SPPC Data Request response to Barrick Goldstrike Mines in Docket No. 01-11030, which states that, "At the present time market prices are approximately 30% to 40% lower than the costs that were utilized in the study to calculate marginal cost." (Exhibit 109 at p. 3 and p. 6-8.)

429. During cross-examination by MGM's counsel, Dr. Swan concurred with NPC that an "across the board" reduction in marginal energy costs would not affect the time pattern of marginal energy costs and the relative cost responsibilities among customer classes. However, a

"Full-on-Full" marginal cost reconciliation would change the relative customer class cost responsibility. (Tr. at p. 1460-1462.)

BCP's Position

430. Mr. Marcus, witness for the BCP, asserted that NPC's marginal energy costs were developed ignoring FERC's price cap of $92 per MWH. The BCP estimated that if NPC had included FERC's price cap in the development of its marginal energy costs, the summer on-peak energy prices and mid-peak energy prices would be reduced by 20.16 percent and 4.58 percent, respectively. (Exhibit 114 at p. 12-13.)

Staff's Position

431. Staff concluded that NPC's marginal cost of service study is an appropriate method of allocating costs between customer classes in this proceeding. (Exhibit 106 at p. 5.)

NPC's Rebuttal Position

432. NPC's rebuttal witness, Ms. Lipparelli, stated that the primary reason NPC did not update either its market price forecast or marginal energy costs is because there would be minimal impact upon the customer classes cost responsibility if the new forecast had a similar price profile shape, and if a functional reconciliation was used. (Exhibit 117 at p. 24-25.)

433. Ms. Lipparelli stated that she did recognize FERC's price cap by setting the average peak price for the months of July and August at $92. But she did not implement the price cap for any single hour since its inclusion would distort the hourly price profile, which reflects the relative value of power in different time of use periods. Further, Ms. Lipparelli noted that FERC's price caps terminate in September 2002, and the rates developed in this proceeding will continue in effect until 2004. (Id. at 9.)

Commission Discussion and Findings

434. If a "Full-on-Full" marginal cost to embedded revenue requirement reconciliation were performed, a change in the market energy price could by itself affect the customer classes' cost responsibility. However, as discussed earlier in this order, the Commission has accepted NPC's functional marginal cost reconciliation methodology.

435. A change in the market energy price profile could change a customer classes' cost responsibility under either marginal cost reconciliation methodologies. No Party to this portion of the proceeding besides the BCP criticized NPC's price profile. BCP's proposal to implement FERC's power price caps for all hours modifies the price profile by reducing the summer time of use power price differentials.

436. Since the rates developed in this proceeding could still be in effect until 2004, and FERC's price caps are set to expire in September 2002, the Commission concurs with NPC that implementation of FERC's price caps on an hourly basis would inappropriately distort the energy price profile. Therefore, the Commission finds that NPC's marginal energy costs are reasonable and approved.

E. Hoover B Benefit Allocation

BCP's Position

437. BCP witness, Mr. Marcus, asserted that NPC made two errors in its treatment of Hoover B benefits in the marginal cost allocation. First, Mr. Marcus contended that NPC did not allocate any Hoover B capacity benefits to the residential customer classes. The 135 MW in capacity was not eliminated from the residential customer classes' capacity requirements prior to allocating the marginal generation capacity costs. Second, Mr. Marcus asserted that NPC's reconciliation of marginal energy costs to energy revenue requirement diluted the Hoover B energy benefit. The embedded benefit value is used in reducing the marginal energy costs allocated to the residential class, effectively providing only 81 percent of the benefit to the residential classes. (Exhibit 114 at p. 43-44 and Tr. at p. 1513.)

NPC's Rebuttal Position

438. Ms. Lipparelli stated that NPC calculated the Hoover B capacity and benefit in accordance with an existing stipulation. Specifically, NPC developed the system wide marginal generation and marginal energy costs for all customer classes and then reduced the residential classes marginal costs by the Hoover B benefit value developed in the Deferred Energy Case. Ms. Lipparelli agreed that utilizing NPC's methodology is appropriate to escalate Hoover B benefit levels to that of the marginal costs. (Tr. at p. 1606-1607.)

Commission Discussion and Findings

439. NPC's rebuttal witness, Ms. Lipparelli, asserted that NPC's treatment of Hoover B complied with an existing stipulation. While the stipulation was not identified, the only existing stipulation regarding the rate making treatment to be afforded Hoover B energy was that accepted by the Commission in Docket No. 99-7035.

440. As stated by the Presiding Officer in this matter, the record in the Deferred Energy Case (Docket No. 01-11029) may be used to resolve issues in this proceeding. (Tr. at p. 1630.) A review of the record in the Deferred Energy Case disclosed that no Party to that proceeding took exception with the applicability of the Stipulation in Docket No. 99-7035 or

with NPC's Hoover B benefit calculation or rate treatment. Mr. Branch's Hoover B benefit calculation and ratemaking treatment (as outlined in Docket No. 01-11029 at Statement E-1) compares to the methodology set forth in the Docket No. 99-7035 Stipulation at Paragraph 3 and at Exhibits A and C.

441. While NPC is modifying the BTER in the Deferred Energy Case, it is necessary for NPC to reflect a similar Hoover B benefit in the marginal cost study to arrive at the appropriate customer class responsibility.

442. BCP's proposed marginal generation capacity cost adjustment associated with the 135 MW of Hoover B capacity creates a benefit beyond that set forth in the Docket No. 99-7035 Stipulation. NPC concurred that its valuation of Hoover B benefit at embedded costs in the allocation of marginal costs is inappropriate.

443. The Commission finds that NPC's marginal cost study appropriately accounted for the Hoover B benefit; however, in order to have a proper comparison the Hoover B benefit used in the marginal cost study shall be adjusted to its marginal cost value.

F. Customer Facilities Costs

NPC's Position

444. Ms. Lipparelli stated that NPC's derivation of marginal facilities costs consisted of developing the typical investment made for a customer in a particular rate class, with the exception of the LGS-X class, which had a customer specific rate. The investment is converted to an annual charge using an economic carrying charge and the appropriate adders. (Exhibit 96 at p. 4.)

445. Dr. Edward Ives, witness for NPC, stated that marginal facilities investments are the local distribution facilities installed to serve the loads of new customers, and not the investments needed to serve the combined loads of the whole system. In order to derive the appropriate marginal facilities cost, Dr. Ives stated that it is necessary to consider both Rule 9 and subdivision rules. These regulations establish the cost requirements associated with new business.

446. NPC's investment in any new customer project is the allowance granted, and any portion of the refundable allowance advance is refunded to an applicant. Further, Dr. Ives stated that its necessary to eliminate over sizing as the new business applicant is not responsible for these costs. Dr. Ives observed that since the Rule 9 allowances are a function of existing rates it is necessary to implement an iterative process wherein the marginal customer facilities costs,

thus the marginal cost study, is adjusted to reflect the rates authorized by the Commission in the instant proceeding. (Exhibit 99 at p. 2-4 and 7-8.)

447. In this proceeding, Dr. Ives noted that NPC's proposed customer classes' facilities investment is based upon information from an analysis of 2000 new business projects that were completed during July 1989 through June 2001. NPC noted that since actual over-sizing investment cost is not available for any project, it attempted to indirectly remove these costs from the projects analyzed. (Id. at 4-5 and Exhibit 100 at p. 3-5.)

DOE's Position

448. Dr. Swan for the DOE recommended that the Commission exclude the capital costs associated with meters and service drops from the development of marginal costs on the basis that the majority of these costs are sunk. However, Dr. Swan acknowledged that the Commission has not previously accepted his suggested adjustment. (Exhibit 109 at p. 9.)

BCP's Position

449. The BCP witness Mr. Marcus recommended that the Commission adopt the "hookup" method for the development of customer facilities charges in lieu of NPC's "rental" method. Mr. Marcus described the "hookup" method as being calculated by multiplying the "hookup" investment by the number of new and replacement customers added to the system. Specifically, Mr. Marcus recommended that the calculation be performed by applying the average percentage change in new hookups for 1996-2005 be multiplied by the actual customers of each class to reduce volatility caused by economic conditions. (Exhibit 114 at p. 14 and 18.) Mr. Marcus asserted that this method improves economic efficiency as these costs are truly only avoidable upon installation, and this method likens customers' acquisition of system access to the customers' purchase of durable goods in the competitive market. Further, Mr. Marcus noted that the most economically efficient method for capturing these costs would be to charge a customer a hookup fee. (Id. at 15-17.)

450. Mr. Marcus noted that the database used by NPC in its customer facilities analysis included a block of costs associated with "over sizing" facilities. Mr. Marcus recommended that the costs associated with over sizing facilities (classified as customer facilities) be allocated upon demand between customer classes since it is a "non-revenue feeder" distribution investment cost, rather than allocate those costs on a customer basis as those facilities were installed to ensure the ability to serve future demand. (Id. at 23.)

NPC's Rebuttal Position

451. Regarding Dr. Swan's recommendation, Dr. Ives asserted that for many years the Commission has utilized long-run marginal costing, which holds a customer directly responsible for the full cost of the connection at the time of the connection via the on-going payment of marginal cost prices for the investment. Further, Dr. Ives contended that if these costs are excluded from the marginal costs calculation the customers' accountability for this investment is denied and the reconciliation process will be abused. (Exhibit 116 at p. 24.)

452. Ms. Lipparelli stated that since NPC does not track over sizing of local facilities, or feeder distribution, NPC has a limited ability, in accordance with Rule 9, to recover over sizing investment from subsequent customers. Therefore, it is not possible to accurately estimate the over sizing costs that should be included as a customer facility cost. Further, Ms. Lipparelli asserted that, while NPC's exclusion of over sizing investment may understate the customer facilities costs, NPC believes it is appropriate to only include those costs that can actuarially be estimated. (Exhibit 117 at p. 15-16.)

453. Dr. Ives asserted that the BCP's recommendation fails to properly recognize that replacement cost is irrelevant to serving new customers. Dr. Ives contended that since replacement costs are part of the life cycle cost, these costs should be considered in the marginal cost and pricing to service a customer. Further, Dr. Ives asserted that NPC's marginal cost methodology appropriately included replacement costs. (Exhibit 116 at p. 16-17.)

454. During clarification questioning by the Commission, Dr. Ives concurred that the "rental" method reflects how the customer is being charged for customer facilities. (Tr. at p. 1618.)

Commission Discussion and Findings

455. As acknowledged by Dr. Swan, the Commission has not previously accepted DOE's recommendation that meters and service drop capital costs should be excluded from the development of marginal customer costs, and the Commission is not persuaded to so in this proceeding.

456. NPC acknowledged that, in accordance with Rule 9, it should have included some level of over sizing investment in its marginal customer facilities cost. Yet NPC asserted that it excluded these costs from its new business project analysis that served as the basis for its customer facilities cost. NPC stated it excluded these costs due to its inability to accurately estimate the costs.

457. While BCP stated that the data base included a block of costs associated with "over sizing" and recommended that these costs should be allocated using demand rather than number of customers, the BCP did not provide any evidence contradicting NPC's assertion that it did remove these costs from its new business project analysis.

458. The NPC's "rental" methodology corresponds with how a customer is charged for the service.

459. Based upon the aforementioned, the Commission finds that NPC's marginal customer facilities charge methodology is reasonable and approved. Therefore, the necessary revenue requirement / Rule 9 iterative process should be performed.

G. Distribution O & M – Transmission - Distribution Split

NPC's Position

460. NPC calculated its estimated marginal distribution O&M expenses used in its marginal cost of service study by using a weighted average for the historical five-year period 1996 – 2000. (Exhibit 96 at Atch LIL-2 and Exhibit 97 at Atch LIL-2-CERT.)

BCP's Position

461. BCP's witness, Mr. Marcus, disagreed with NPC's allocation of distribution expenses during the period of 1996-1998 associated with the "transmission - distribution split". Mr. Marcus asserted that NPC allocated the previously classified transmission expenses to all distribution O&M expense accounts on an equal percentage basis. The BCP proposed that the costs for this time period should be allocated on an equal percentage basis to the following: load dispatching; substations; overhead lines; and corporate overhead accounts 580, 588, and 590. Mr. Marcus stated that his proposed allocation recognizes that "virtually all of the transmission expenses being reassigned are from these functions." (Exhibit 114 at p. 24.)

NPC's Rebuttal Position

462. While Ms. Lipparelli of NPC concurred with Mr. Marcus that the reassigned transmission expenses for the years 1996-1998 associated with the reclassification of transmission plant should be allocated to those accounts that were affected, Ms Lipparelli disagreed with BCP's selected accounts. Based upon information obtained from its plant accounting department, NPC proposed to modify its initial allocation to exclude accounts 581, 585-589, and 595-598 from the reassignment processes, and to reallocate the costs initially assigned to these accounts to the remaining distribution accounts based upon those accounts' existing expense levels. (Exhibit 117 at p. 16-17.)

Commission Discussion and Findings

463. As noted by the BCP, NPC's proposed reallocation of the previously classified transmission expenses among various distribution expense accounts is not totally accurate. But no Party to this portion of the proceeding disagreed with NPC's revised allocation of the previously classified transmission expenses among distribution expense accounts.

464. Based upon the aforementioned, the Commission finds NPC's revised allocation reasonable and approved.

H. Distribution O & M – Substation

BCP's Position

465. The BCP proposed to reclassify load dispatching expenses from distribution facilities to substation O & M expense, as this activity is related to large distribution system elements (substations and feeder lines) rather than localized facilities (e.g., transformers). (Exhibit 114 at p. 25.)

466. In addition, the BCP proposed to reclassify grid meter expenses from meter O & M and customer accounting expenses to substation O & M expense. Mr. Marcus noted that in Docket No. 99-4005, NPC cited these types of meters as being typically installed in substations to measure demand over large areas. BCP contended that since these costs are integral to both the operation of the substation and to system reliability, the associated costs were equivalent to substation demand costs (Accounts 582 and 592). As such, these costs should not be allocated using traditional meter allocators. Further, since NPC didn't provide any substantive information to the contrary, the BCP proposed that the Commission accept the estimated cost ratios of 9.82 percent of meter O & M expenses and three percent of customer accounting expenses from Docket No. 99-4005. (Id. at 25-27.)

NPC's Rebuttal Position

467. NPC's rebuttal witness, Ms. Lipparelli, disagreed with BCP's proposal to reassign load dispatching to substations since NPC estimates a minimal amount of these costs are directly associated with substations. (Exhibit 117 at p. 17-18.)

468. NPC disagreed with the BCP's proposal to re-assign grid meter costs to substations rather than to customer facilities. While acknowledging that grid metering is essential for the provision of distribution services, Ms Lipparelli stated that the Commission should not accept BCP's proposed adjustment because the expenses are not tracked and the Docket No. 99-4005 estimate may not accurately equate to the actual costs. If accepted, this

would have a de minimus effect. Prior to the reconciliation processes, NPC estimated the impact to be a decrease in the residential classes' monthly expenses of 1.1 percent. (Id. at 18-19.)

Commission Discussion and Findings

469. The BCP did not provide sufficient justification as to why NPC should reclassify load-dispatching expenses from a facilities cost to a substation cost. Therefore, the Commission finds that NPC's classification of load-dispatching expenses is reasonable and accepted.

470. NPC did not disagree with the BCP's assertion that grid meters are associated with substation activity. NPC only disagreed with the amount proposed by BCP. NPC stated that since it does not track these costs, no accurate amount may be determined and application of BCP's proposed ratios results in an immaterial impact upon the costs allocated to the residential customer classes.

471. The Commission finds that NPC should commence tracking costs associated with grid meters and in its next general rate case classify the costs as a substation cost.

I. Allocation of Facilities O & M Expenses Between Customer and Demand

BCP's Position

472. BCP's witness, Mr. Marcus, recommended that the facilities O & M expenses be allocated between customer facilities and demand facilities using "replacement cost new" methodology, wherein comparing the replacement develops the ratio for these facilities costs for that category of facilities to the total replacement cost for both customer facilities and demand facilities. Mr. Marcus stated that his proposal would increase the demand facilities allocation from eleven percent to thirty-two percent. (Exhibit 114 at p. 27-28.)

473. Further, Mr. Marcus stated that NPC relied upon future investment patterns rather than on the "standing stock of equipment", which is the basis for his methodology. (Id. at 28.)

NPC's Rebuttal Position

474. NPC's rebuttal witness, Ms. Lipparelli, acknowledged Mr. Marcus' concern about NPC's reliance upon only forecasted investment to estimate customer and demand allocation of facilities O & M. Ms. Lipparelli proposed using a combination of historical and recent projected years (2000 and 2001) plant balances rather than BCP's proposed "replacement cost new method", which method could introduce an unwarranted level of uncertainty. NPC's proposal would increase the demand facilities allocation from eleven percent to thirteen percent. (Exhibit 117 at p. 19-20.)

Commission Discussion and Findings

475. Both NPC and BCP agreed that total reliance upon future investments is an inappropriate manner to allocate facilities O & M to customer and demand facilities. BCP proposed reliance upon existing stock valued at replacement cost, whereas NPC proposed using a combination of historical and projected plant balances. The Commission believes that NPC's proposed revised methodology addresses the total reliance upon future investment without adding the complexity of the "replacement cost new" methodology. Therefore, the Commission finds NPC's proposed revised methodology, as outlined in its rebuttal testimony, reasonable and approved.

J. Uncollectible Account Expense

BCP's Position

476. Mr. Marcus for the BCP proposed that the customer accounts expense be adjusted to exclude $7.35 million in uncollectible expenses associated with surplus energy sale to the California PX and ISO because these costs are not associated with NPC's retail customers and NPC excluded this cost from its proposed revenue requirement. (Exhibit 114 at p. 29-30.)

477. The BCP also proposed that the remaining uncollectible expenses be excluded as these are not marginal costs to bill-paying customers, and no clear way exists to allocate these costs under marginal costing theory. Mr. Marcus stated that California has excluded these costs from its marginal cost studies for 15 years, and the BCP's witness, Mr. Brosch, has demonstrated that NPC has significantly overstated its uncollectible expense. (Id. at 29-32.)

NPC's Rebuttal Position

478. Ms. Lipparelli stated that NPC disagreed with the BCP's proposal to eliminate uncollectible expenses from the marginal cost study. NPC noted that these costs are directly attributable to customers on the system and these costs typically increase with customer growth. Further, Ms. Lipparelli argued, as with the use of energy losses, inclusion of uncollectible expenses is necessary to accurately estimate the revenue per customer that will occur by recognizing that some level of revenue will go unpaid. (Exhibit 117 at p. 14.)

479. However, NPC did concur with Mr. Marcus that the $7.35 million in uncollectible expense associated with the California PX and ISO should be excluded from the year 2000 customer account expenses used in the marginal cost study. NPC stated that the adjustment does not materially affect the study. (Id. at 13-14.) Regarding the level of uncollectible expense, Ms. Lipparelli stated that NPC presented rebuttal testimony on this issue. (Id. at 14-15.)

Commission Discussion and Findings

480. Inclusion of uncollectible expense in the marginal cost of service study is necessary to recognize that a level of revenues will go unpaid and these costs would need to be recovered from the other customers. The reasonableness of the amount of uncollectible expense is addressed elsewhere in this order and does affect the need to include the expense in the marginal cost of service study.

481. NPC concurred with the BCP that that the uncollectible expense associated with sales to the California PX and ISO should be eliminated from this marginal cost of service study.

482. The Commission finds that uncollectible expenses should be included in the marginal cost of service study; however, NPC needs to exclude the expenses associated with sales to the California PX and ISO from its study. Therefore, the inclusion of uncollectible expenses in NPC's marginal cost of service study is reasonable and approved.

K. Customer Service and Information Expense

BCP's Position

483. Mr. Marcus for the BCP cited one concern with NPC's customer service and information expense portion of the marginal cost of service study; the level of costs associated with the "Energy Efficiency" department. Mr. Marcus stated that the $7.85 million used by NPC exceeds both that experienced by NPC for ratemaking purposes in previous years, and the Test Year costs of $25,000. Mr. Marcus asserted that the current year $25,000 expense serves as a better measure of NPC's on-going marginal costs than the five-year average. But since it is an immaterial amount, it need not be excluded on the basis that demand side measures costs are not properly classified as a marginal customer cost. (Exhibit 114 at p. 34 and 36.)

484. The BCP further contended that demand side measure costs are driven by utility and state policy concerns, and are therefore akin to investments in the acquisition of energy or generation. Thus these costs should not be allocated on the basis of number of customers. (Id. at 34-35.)

NPC's Rebuttal Position

485. Ms. Lipparelli stated that NPC disagreed with BCP's proposal to include only $25,000 of "Energy Efficiency" department expenses in the marginal cost study. NPC asserted that the department had only been in existence for a portion of the Test Period; thus, a full year of expenses had not been experienced. In order to correct this understatement, NPC used the department's budgeted 2002 expenditures of $7.9 million in the development of the customer

weighting study. Further, Ms. Lipparelli stated that prior to the year 2000 NPC had had a similar department. The 2002 budget expenses of $7.9 million were consistent with these prior year expenses (1995 through 1998 the expenses were $6 million to $7 million). (Exhibit 117 at p. 10-12.)

486. While NPC concurred that demand side program costs approved in a resource plan are more generation related, and would be included in a general rate case in accordance with the Commission's regulations, the costs the BCP propose to remove from Account No. 908 are primarily related to customer assistance and education to enhance safe and efficient energy use. Further, NPC contended that while the majority of these programs may reduce residential and small commercial demand, NPC is unable to rely upon any reduction in these areas at this point in time. (<u>Id.</u> at 12-13.)

<u>Commission Discussion and Findings</u>

487. Due to the creation of the "Energy Efficiency" department during the Test Year, a full year of expenses were not incurred. NPC dealt with this situation by using the department's budget of $7.9 million in the customer weighting study. NPC's estimated expenditures of $7.9 million in 2002 dollars approximates historical expenditures. Therefore, the Commission finds that NPC included a reasonable "Energy Efficiency" department expense amount in the customer weighting study.

L. Other Revenue-Late Payment Fees

<u>BCP's Position</u>

488. The BCP recommended that late payment fees and uncollectible expenses be treated consistently for marginal cost study purposes; namely, if one is included so should the other be, and if one is excluded so goes the other. Otherwise, the BCP contended, residential customers would be charged for uncollectible expenses "but not given credit in the allocation for paying a disproportionate share of late payment fees." Additionally, the BCP stated that by using the BCP's proposed uncollectible expense level, the late payment fees offset uncollectible expense. (Exhibit 114 at p. 32-33, and 45.)

<u>NPC's Rebuttal Position</u>

489. Ms. Lipparelli stated for NPC that it is important to note that uncollectible expenses are not directly related to late payment fees, since the former is a write off for non-payment and the latter encourages payment. In response to the BCP's assertion that the consumers do not benefit from late payment fees, Ms. Lipparelli asserted that late payment fees,

and all Other Revenues, are excluded from the rate revenue requirement; thus, all customers receive an equitably proportional allocation based upon the classes' contribution to total marginal cost. Specifically, Ms. Lipparelli stated that a comparison of schedule PMF-5, at page 2 line 1, rate revenue requirement, to Statement O, supports NPC's assertion. (Exhibit 117 at p. 22-23.)

Commission Discussion and Findings

490. As demonstrated by NPC's comparison, the late payment fees, and all Other Revenues, are included in NPC's revenue requirement. This reduces the revenue requirement to be collected through rates. Thus, all customer classes have been allocated a share of these revenues. The BCP failed to demonstrate a direct link between uncollectible expenses and late payment fees.

491. Based upon the foregoing, the Commission finds NPC treatment of late payment fees to be reasonable and approved.

M. Other Revenue-Excluding Late Payment Fees

BCP's Position

492. The BCP's witness, Mr. Marcus, recommended that Other Revenues associated with tariffed services (e.g., service reconnection fees) be included in the marginal cost of service study as the associated costs being recovered by these revenues had been included in the study. Mr. Marcus stated that the residential customers pay 94 percent of these tariff service revenues. Mr. Marcus argued that inclusion of the associated service costs in rates results in the customer paying twice for these services, once in general rates and again paying for the specific service. Specifically, Mr. Marcus recommended that the Other Revenues, excluding late charge fees, be allocated to each customer class based upon actual payments and that these revenues be used to specifically offset distribution service costs. (Exhibit 114 at p. 45-46 and Atch WBM-7 p. 1.)

NPC's Rebuttal Position

493. NPC's witness, Ms. Lipparelli, asserted that all Other Revenue is excluded from the rate revenue requirement thus all customers receive an equitably proportional allocation based upon the class's contribution to total marginal cost. Specifically, Ms. Lipparelli stated that a comparison of schedule PMF-5, at page 2 line 1, rate revenue requirement, to Statement O, supports NPC's assertion. (Exhibit 117 at p. 23.)

Commission Discussion and Findings

494. As demonstrated by NPC's comparison, all Other Revenues are included in NPC's revenue requirement, thereby reducing the revenue requirement to be collected through rates. Thus, all customer classes have been allocated a share of these revenues. The equitably proportional allocation need not match the actual payment stream for these tariffed services. For example, using the total marginal cost as the allocation basis, the residential customer class receives 50 percent of these revenues, whereas these customers paid 94 percent of the revenues ($2.9 million versus $5.5 million of the total $5.86 million).

495. Due to the potential significant shift between customer classes, and the Commission's rate rebalancing decision in this proceeding, the Commission finds NPC's treatment of Other Revenues, excluding late payment fees that were previously discussed, reasonable. However, in future proceedings, NPC will be required to allocate Other Revenues between customer classes based upon the customer classes' payment of the tariff service revenues to the extent reasonably possible.

VI. Rate Design

A. Rate Rebalancing Adjustment

NPC's Position

496. Joanne Meacham, witness for NPC, stated that NPC had complied with previous Commission directives by limiting the increase in revenue requirement for any class to no more than the overall system average increase, plus five percent. NPC recovered the difference between a customer classes' cost based allocated embedded revenue requirement and the capped customer class revenue requirement from the other customer classes. Ms. Meacham further stated that the rebalancing adjustment provides the movement towards cost based rates while limiting a customer classes' potential rate shock. (Exhibit 101 at p. 3-4.)

497. During questioning by the Commission, Ms. Meacham agreed that given today's economic conditions it was appropriate not to make an incremental step towards cost based rates. (Tr. at p. 1322-1323.)

Staff's Position

498. Based upon Staff's proposed revenue requirement reduction, Staff's witness Ms. Bellard stated that it is unnecessary to apply the rate rebalancing adjustment since the residential customers' classes would be subject to a small increase, approximately 11 percent. Further, Ms.

Bellard stated that movement to cost based rates now will avoid future rate effects caused by the eventual elimination of the residential subsidy. (Exhibit 106 at p. 5-6 and Tr. at p. 1411.)

499. Under cross-examination by NCCEU's attorney, Ms. Bellard stated that implementation of cost based pricing would increase future rate stability and enhance conservation. (Tr. at p. 1400-1401.) Additionally, Ms. Bellard agreed that both residential consumers and businesses are facing tough economic times. (Tr. at p. 1402.)

500. During cross-examination by USAN's attorney, Ms. Bellard expressed Staff's opinion that regardless of the Commission's revenue requirement determination the rate rebalancing adjustment should be eliminated. (Tr. at p. 1402.)

501. Upon clarification questions by the Commission, Ms. Bellard concurred that during approximately the last twenty years a significant stride has been made toward moving the residential customer class to cost based rates. Ms. Bellard noted that the Order issued in Docket No. 83-707 stated that moving the residential customer class to cost base rates would result in a 50 percent increase in that proceeding. But using NPC's revenue requirement, the residential customer class would experience only a 16 percent increase in this proceeding. (Tr. at p. 1411-1412.)

SNWA's Position

502. Witness for SNWA, Dr. Peseau, recommended that any rate cap in this proceeding be applied to the total average increases from both this proceeding and the Deferred Energy Case, including the DEAA. Further, Dr. Peseau advised that if the Commission authorizes a revenue requirement reduction in this proceeding, a rate cap might not be needed. (Exhibit 108 at p. 17 and Tr. at p. 1447 and 1457.)

503. During clarification questioning, Dr. Peseau stated that while the SNWA desires to move quickly towards marginal costing, the SNWA would not want an unconstrained rate adjustment in this proceeding. (Tr. at p. 1457-1458.)

DOE's Position

504. The DOE did not recommend implementation of cost based rates for rate continuity purposes. However, the DOE did recommend, given the significant increase being requested by NPC, increasing the rate cap. Witness for DOE, Dr. Swan, requested the Commission increase the rate cap from five percent to ten percent and include all revenues (i.e., Base Tariff General Rate, Base Tariff Energy Rate, and Deferred Energy Accounting Adjustment) in the calculation. (Exhibit 109 at p. 21.)

MGM's Position

505. Mr. Garrett for MGM stated that it is not MGM's recommendation to eliminate the rate rebalancing adjustment, because rate rebalancing could not be achieved without exposing the residential classes to substantial rate increases. The MGM did recommend, as a means to mitigate the residential classes' subsidy, that the residential customer classes not participate in any revenue requirement reduction approved by the Commission in this proceeding. Alternatively, if the Commission desires to have all customer classes to participate in any revenue requirement reduction, MGM advised that both goals could be achieved by allocating to the residential customer classes a percentage of the revenue requirement reduction that is lower than their equitably proportional allocation (for example, 20 percent rather than 53 percent). If no revenue requirement reduction occurs, MGM recommended retention of the rate rebalancing adjustment. (Exhibit 110 at p. 5-12 and Tr. at p. 1469-1471.)

NEBG's Position

506. Dave Gildersleeve, witness for NEBG, recommended that the Commission eliminate the rate rebalancing adjustment because it places an unreasonable burden on the non-residential customer classes. Mr. Gildersleeve argued that the rate rebalancing deviates from cost based rates, and the Commission opined in General Order No. 36, in Docket No. 82-239 Opinion at page 6 that, as the primary basis for rates: "cost of service ought to be the single most important factor to be considered when designing rates." Further, Mr. Gildersleeve argued that the residential customer class subsidy is unnecessary given that these customers already receive the benefit of lower cost power from the Hoover Dam. (Exhibit 111 at p. 2-3.)

507. Alternatively, if the Commission were to authorize a revenue requirement lower than that requested by NPC, the NEBG recommended that the Commission allocate any revenue requirement reduction to all non-residential customer classes and then apply the rate rebalancing adjustment. (Id. at 4.)

NCCEU's Position

508. NCCEU witness, Dr. Dan Berry, recommended the elimination of the rate rebalancing adjustment since it neither complies with the Commission's regulations, specifically NAC 704.662, nor provides for efficient pricing. Additionally, Dr. Berry referenced NARUC's 1992 *Electric Utility Cost Allocation Manual* that states that, "few analysts seriously question the standard that service should be provided at cost." (Exhibit 112 at p. 5 and 9-10.)

509. During cross-examination by Staff's attorney, Dr. Berry stated that the Commission could deviate from setting rates based upon marginal cost for the reasons cited in its regulations, specifically NAC 704.662. Dr. Berry identified the relevant criteria as: insignificant differences in seasonal or hourly rates; cost of meters to measure hourly differences exceeding the benefits; and the application of the rate would unreasonably affect the utilities financial health. In this instance, Dr. Berry stated, these criteria do not apply. While not acknowledging the remaining exceptions, Dr. Berry did read them into the record: the rate would not be equitable or the excepted level of understanding or acceptance of the rate would not likely serve the purpose of this regulation. (Tr. at p. 1484-1487.)

510. In addition to the rationale expressed by Dr. Berry, NCCEU witness Scott Craigie asserted that the Commission rejected the implementation of a five percent rate cap in the Commission's marginal cost regulations[23], and if the Commission desired to make the cap permanent it would have modified the regulations. (Exhibit 113 at p. 3, 4 and 6.)

511. Mr. Craigie cited the Commission's rational for instituting the five percent cap in NPC's rate case Docket No. 83-707 in the Opinion and Order at page 77:

> "We believe that continuity in rates and gradualism in rate design changes along with the unanimous recommendation (of all parties in this case) require the imposition of a 5% cap."

Mr. Craigie further stated that the rationale set forth by all the parties in the 1983 general rate case was "to ease the transition into this new cost of service standard." (Id. at 5-6.)

512. Mr. Craigie stated that "Gradualism" shouldn't take two decades; the Commission had several opportunities to remove the rate cap in previous NPC rate proceedings. However, Mr. Craigie noted that most of those cases were settled by stipulations, thereby eliminating the Commission's opportunity to eliminate the use of the cap. (Id. at 6 and Tr. at p. 1497.) Mr. Craigie contended that the elimination of the rate subsidies would eliminate the large commercial customers' economic and emotional incentives to leave the system. (Exhibit 113 at p. 11.)

513. During Commission questioning, Mr. Craigie stated that the southern Nevada economy is "hurting on many fronts" as both the gaming industry and the growth industry, primarily construction, have been experiencing a decline. Mr. Craigie agreed that historically the

[23] NAC 704.665 et seq.

economic down turns experienced by southern Nevada have lasted eighteen to twenty-four months; thus, a possible turnaround could occur in 2003. (Tr. at p. 1498-1499.)

BCP's Position

514. Due to the combination of the requested general rate increase and significant DEAA increase, BCP recommended retention of the rate rebalancing adjustment as proposed by NPC, a five percent cap, in order to prevent rate shock. This is demonstrated by the BCP's inclusion of the rate rebalancing in its proposed customer marginal cost revenue allocation, even though the BCP proposed a $50.8 million revenue requirement reduction. (Exhibit 66 at Schedule E, Exhibit 114 Atch WMB-4 and Tr. at p. 1517-1518.)

Commission Discussion and Findings

515. Commencing in NPC's 1983 general rate case, significant movement towards cost based rates have been achieved. This is demonstrated by the reduction from the nearly 50 percent increase in residential customers rates that would have been required in 1983 using NPC's revenue requirement, to an approximately 16 percent figure today.

516. Even with the revenue requirement and associated rates approved in this proceeding, the potential for the residential customer classes to experience rate shock still exists due to NPC's Deferred Energy Application in Docket No. 01-11029. The BCP highlighted this by applying the rate rebalancing adjustment even though they are proposing a $50.8 million revenue requirement reduction in this proceeding.

517. During the eighteen years since the decision in NPC's 1983 general rate case, the Commission has had limited opportunity to address the issue of moving the residential customer class to cost based rates. In that time, NPC filed two general rate cases with the Commission and four stipulations reducing NPC's rates. While only the last stipulation (Docket No. 93-11045) addressed moving the residential customer class towards cost based rates, the Commission accepted the other three stipulations. With most stipulations the Commission's choices are generally limited to accepting or rejecting the settlement. While the orders' language varied among these three stipulations, the meaning was the same; the Commission found these settlements to be in the public interest and thus accepted them. Therefore, it must be presumed that the Commission found other public policy issues being served by these settlements that were more pressing than a move toward cost based rates, or the settlements would have been rejected.

518. The Commission's regulations allow the deviation from marginal cost of service for the establishment of rates for several reasons. One reason outlined in NAC 704.662.1(c)(2):

"The expected level of understanding or acceptance of the rate by the customers of the class to which the rate would apply is such that the rate would not likely serve the purpose of this regulation." No Party in this portion of the proceeding addressed this exception.

519. At the public consumer sessions in this matter, which were heavily attended, it became overwhelmingly evident that the residential customer class had limited understanding and acceptance of the proposed rates. It is the Commission's opinion that additional movement toward cost based rates in this proceeding would serve only to exacerbate the residential customer classes' lack of understanding and acceptance.

520. There is no disagreement that the current southern Nevada economic slowdown has detrimentally affected both residential consumers and commercial entities. During this difficult time, all customers are looking toward this Commission to mitigate the historically high energy rates. While additional movement of the residential customer classes towards cost based rates would provide a measure of relief to the other customer classes, additional movement of the residential customer classes towards cost based rates would aggravate the residential customer classes current economic situation. At this time, the Commission believes that all classes would best be served by holding in abeyance further movement of the residential customer class to cost based rates.

521. Historically, southern Nevada economic slowdowns tend to have a life cycle of eighteen to twenty-four months, which indicates a potential turn around in 2003. In accordance with NRS 704.110.3, NPC's next general rate change application will be filed in late 2003. Accordingly, the suspension of the residential customer classes' movement to cost based rates is anticipated to be of limited duration.

522. Based upon the above, the Commission finds that all additional movement of the residential customer classes towards cost based rates should be held in abeyance until NPC's next general rate proceeding, and that all customer classes should share in an equal proportional manner, exclusive of BTER revenues, the revenue requirement change authorized in this proceeding.

B. Monthly Distribution Charge

NPC's Position

523. Ms. Meacham of NPC stated that NPC's proposed monthly distribution charges, except for residential and small commercial classes, are cost based. This is because the distribution system costs are largely fixed in nature and are tied to the customer class's highest

expected peak. In order to mitigate the impact upon the residential and small commercial classes, NPC's proposed monthly charges serve as a step towards cost based rates in this proceeding, which gives consideration to the previously discussed gradualism concept. (Exhibit 101 at p. 5-6 and Tr. at p. 1358-1361.)

524. A comparison of the requested monthly distribution charge contained in the Certification Filing, Statement O, with that contained in Statement O Appendix, the unmitigated rate design, demonstrated that the proposed monthly charges are significantly lower than full cost based rates:

Residential-Multi Family	$12.00 versus $15.83
Residential-Single Family	$19.00 versus $27.96
General Service	$21.00 versus $23.97

536. NPC's proposal in this proceeding was to recover the customer charge and customer facilities costs, rounded to the nearest dollar, and retain the recovery of the non-revenue distribution system costs (feeders and substations) through the energy charge. (Exhibit 102 at Statement O at p. 5 and Statement O Appendix at p. 2, and Tr. at p. 1359-1361.)

525. Ms. Meacham further stated that the significant increase in the LGS-X customer class is marginal cost driven, cited as the primary contributing factor the new customer weighting study, which recognized this customer class for the first time as a separate customer class. Ms. Meacham also stated that NPC proposed, with the exception of residential and small commercial customers, to apply the same distribution rates for both bundled and distribution only service, including the monthly customer charge. (Exhibit 102 at p. 7, 8, and 12.)

<u>Staff's Position</u>

526. Recognizing that the monthly basic service charge had not changed for nearly a decade, Staff's witness Ms. Bellard proposed a more gradual approach to increasing the monthly basic charge for certain customer classes. Ms. Bellard asserted that NPC's proposed monthly basic service charge would increase the multi-family residential customer class, single residential customer class, and small commercial class by 120 percent, 260 percent and 320 percent; respectively. In Staff's opinion these increases appeared to be excessive. Staff proposed an increase for these customer classes of <u>no more than 60 percent</u>, which reflected an annual increase over the past ten years for multi-family residential and single residential customer classes of 4.5 percent and 6 percent, respectively. (Exhibit 106 at p. 6-7 and Atch AMB-4 and Tr. at p. 1413-1414.)

527. Ms. Bellard further stated that the increase in the monthly basic charge would enhance NPC's revenue stability since a larger amount of revenues would be recovered through a fixed charge. However, Ms. Bellard also stated that the increase in the monthly basic charge would reduce the customers' ability to control their total bill by modifying their usage through conservation or better investment. (Exhibit 106 at p. 7 and Tr. at p. 1414.)

528. Staff proposed monthly basic service charges that differ from NPC's as follows:

Residential Service-Multi Family	$8.00
Residential Service	$9.50
General Service	$9.50
Large General Service, Extra Large-Secondary	$1,200.00
Large General Service, Extra Large-Primary	$1,300.00
Large General Service, Extra Large-Transmission	$1,400.00
Large General Service, Extra Large Water Pumping-Secondary	$1,200.00
Large General Service, Extra Large Water Pumping-Primary	$1,300.00
Large General Service, Extra Large Water Pumping-Transmission	$1,400.00

(Exhibit 106 at Atch AMB-5.)

<u>SNWA's Position</u>

529. Dr. Peseau for SNWA recommended that the Commission require NPC to implement the rate design authorized in Docket No. 99-4005 concerning all customers with loads greater than 3,000kW, and taking service at transmission voltage, that charged a facilities charge for the facilities actually used to serve that customer rather than on the customer class average cost. Specifically, Dr. Peseau stated that in compliance with the Commission's order in Docket No. 99-4005, NPC determined the monthly facilities costs associated with service to SNWA's Hacienda facilities (a Schedule LGS-3-WPT customer), to have been $57, whereas in this proceeding NPC's proposing to charge a monthly rate of $13,875. (Exhibit 108 at p. 3, and 13-16)

<u>BCP's Position</u>

530. Mr. Marcus for BCP recommended no change to the residential and small commercial classes monthly distribution charge since the current rate covers NPC's customer accounting and metering costs, if it's presumed that the tariffed service categories of Other Revenues were included in the marginal cost study (e.g., reconnection fees). Alternatively, if the

Commission determines an increase is warranted, the BCP recommends the Commission include no more than 50 percent of the facilities costs in the monthly charge. (Exhibit 114 at p. 55-56.)

531. Mr. Marcus asserted that a usage based rate restructure more fairly charges residential customers for demand related distribution costs than does a flat rate. Mr. Marcus argued that NPC's proposed flat rate methodology ignores the fact that demand related transmission and distribution costs caused by high summer loads can be shifted to winter months. Further, Mr. Marcus argued that NPC's flat monthly charge methodology fails to charge the more affluent residential customer subclass the additional distribution system costs incurred to provide their service, thus shifting the burden to the less affluent residential customers. BCP contended that inclusion of the distribution facilities costs in the energy rate achieves a better cost-causation assignment. Additionally, Mr. Marcus stated that in the absence of demand meters, energy charges are a preferable means to collect demand related costs. (Id. at 50-54.)

532. The BCP recommended an alternative inclusion of 50 percent of the customer facilities costs, since this ratio equates to the results of Mr. Marcus' analysis in Docket No. 99-4005, which demonstrated that 55 percent of the facilities costs were demand related with the remaining 45 percent customer related. However, Mr. Marcus stated that his preliminary analysis in this proceeding indicates that the demand related customer facilities costs for multi-family and single family are 33 percent and 60 percent, respectively. Due an inability to explain the difference, Mr. Marcus considers a 50 / 50 split in this proceeding reasonable. (Id. at 56.)

NPC's Rebuttal Position

533. Ms. Lipparelli stated that the current customer charge was never cost based and only recovered a portion of the costs associated with the following: the meter, the service drop, meter reading, billing, and customer service. The customer charge never included a portion of the upstream distribution costs. Ms. Lipparelli further stated that all of these costs are fixed even if energy is not being used. Additionally, Ms. Lipparelli opined that due to the reduction in the BTGR rate, and since most customers are relatively indifferent to a change in the distribution rates, in terms of customer bill impact, only those customers with significantly low usage would receive a net increase. (Exhibit 117 at p. 31 and 33.)

534. While NPC believed that Staff's proposal was a step in the right direction, NPC asserted that Staff's proposal did not provide sufficient movement to cost based rates. NPC contended that Staff did not justify its basis for its gradual approach. Further, Ms. Lipparelli

observed that Staff's gradual approach, which retains intra-class subsidies, is inconsistent with Staff's proposal to eliminate inter-class subsidies by eliminating the rate rebalancing adjustment. (Id. at 32 and 40 and Tr. at 1594.)

535. Regarding the BCP's proposal, Ms Lipparelli observed that Mr. Marcus did not provide any evidence supporting the contention that more affluent customers use more electricity than less affluent customers. In fact, NPC submitted the following information that suggests less affluent residential customers consume more electricity than the average customer, or alternatively, no correlation between income and usage exists:

- Due to the lack of income information, a random survey of accounts in assumed lower-income neighborhoods was performed indicating that less affluent residential customers have higher than average electricity consumption (Exhibit 117 at Atch LIL-REB-9.);
- Under the assumption that low-income customers typically rent or own older homes and have more occupants per resident and less control over their environment (poor insulation, less efficient appliances and no means to improve the conditions), NPC developed the average 2001 residential electricity consumption by year the home was constructed, and it indicated that residential customers with older homes had higher consumption (Id. at Atch LIL-REB-10.);
- As a result of implementation of the tier rate structure, NPC received a number of inquiries from low or fixed income residential customers concerning difficulty in paying their bills due to high usage; and
- In Docket No. 2357, it was determined that there was insufficient evidence to support any correlation between low use and low income.

(Id. at 34-37.)

536. NPC opined that the Commission should be cautious in establishing a rate design that benefits one group of customers where no clear evidence exists as to energy consumption, since it may be detrimental rather than beneficial if less affluent residential customers are high users. Further, NPC opined that it would be more prudent to establish rates based upon costs as it sends the proper price signal to the customer. (Id. at 37-38.)

537. Additionally, NPC asserted that its distribution charge proposal has several beneficial attributes: mitigation of the current intra-class subsidy from high use customers to low

use customers; improvement of the fixed income customers ability to plan their monthly expenses; and mitigation of the consumers peak season bills. (Id. at 38-39.)

538. During cross-examination by counsel for SNWA, Ms. Lipparelli explained that the reason the $57 per month facilities charge for the Hacienda facilities was no longer applicable was because the facilities charge does not include additional upstream facilities reclassified from transmission to distribution as a result of the T & D[24] split. While NPC has retained its existing policy to assess specific large customer facilities charges for those facilities used to serve them, Ms. Lipparelli stated that NPC did not have the resources during the preparation of this general rate application to perform the additional analysis required to develop additional customer specific facilities charges. However, Ms. Lipparelli stated that NPC is willing to "move further along those lines" in future proceedings. Further, Ms Lipparelli opined that a separate monthly facilities charge for the Hacienda facilities would be significantly greater than $57 per month. (Id. at 59-60 and Tr. at p. 1562-1570.)

Commission Discussion and Findings

539. The Commission concurs with NPC that it should be cautious in designing rates for a residential customer class subset without any clear evidence as to that subset's energy consumption. In this proceeding, no clear evidence has been provided supporting the supposition that the more affluent residential customer class subset consumes more electricity than the average customer. In fact, NPC's limited analysis indicates the less affluent residential customer class subset may consume more than the average customer.

540. The Commission also agrees with NPC that several beneficial attributes are associated with increasing the monthly distribution charge, including: mitigation of the current intra-class subsidy from high use customers to low use customers; improvement of a fixed income customers' ability to plan their monthly expenses; and mitigation of the consumers' peak season bills.

541. While both NPC and Staff stated as a goal the mitigation of the impact of cost based distribution rates to residential and small commercial customer classes, neither NPC nor Staff provided any rationale for their respective proposals. NPC's proposal was to include two of the three components listed (customer costs and customer facilities costs), and then round the total to the nearest dollar. Staff's more gradual approach is based upon an apparently arbitrarily determined annual escalation factor.

[24] Understood by the Commission to mean transmission and distribution facilities.

542. The BCP's approach was to retain the existing residential monthly distribution charge since it equates to the monthly customer costs. Alternatively, Mr. Marcus suggested increasing the rate by 50 percent of the customer facilities costs, which is Mr. Marcus's estimate of the non-demand portion of these costs. Yet Mr. Marcus admitted that his preliminary analysis in this proceeding does not support his alternative 50 percent customer facility cost recommendation.

543. Based upon the Parties positions and NPC's Certification Filing Statement O Appendix (Exhibit No. 102, Statement O Appendix, p. 2) the following monthly distribution charge table was prepared for the customer charge:

Customer Class	Current & BCP	Staff	BCP Alt.	NPC Proposed	NPC Cost Based
Multi-Family Residential	$5.00	$8.00	$9.88	$12.00	$15.83
Single Family Residential	$5.00	$9.50	$13.27	$19.00	$27.96
Small Commercial	$5.00	$9.50	$14.40	$21.00	$23.97

544. While all the Parties' proposals to move from the current monthly customer charge contained flaws, retaining the current customer charge rate has a cost, the loss of the benefit attributes previously cited. Since movement toward cost based rates is appropriate, the question arises as to which of the recommendations should be selected. However, for the rationale set forth in the rate rebalancing adjustment discussion previously in this Order, additional movement towards cost based rates for the residential customer classes shall be held in abeyance until NPC's next general rate proceeding.

545. Staff's proposed 60 percent increase in the monthly distribution charge for the small commercial customer class results in significant movement toward cost based rates. Using NPC's Statement O Appendix, which was developed by NPC using a revenue requirement that is greater than that approved by the Commission, Staff's rate will not only recover all the customer

classified costs but a portion of the customer facilities costs. Therefore, the Commission finds Staff's proposed small commercial class's monthly distribution charge reasonable and approved.

546. Since the LGS-X customer class has the potential ability to obtain energy supplies elsewhere and receive only distribution service from NPC, NPC's proposed LGS-X customer classes' monthly distribution charge provides this customer class with the proper price signal to use in its evaluation.

547. SNWA's Hacienda facilities' customer specific facilities charges of $57 per month established in Docket No. 99-4005 did not incorporate the transmission and distribution split. As a result, the charge is understated and shall not be used in this proceeding.

548. NPC explained that a lack of resources prevented it from proposing a policy to establish customer specific facilities charges for large customers and that it was willing to pursue that policy in future proceedings.

549. Based upon the foregoing, the Commission finds NPC's proposed monthly distribution charge methodology, except for residential and small commercial customer classes, reasonable and approved. Further, the Commission finds that NPC should continue to pursue its policy for the development of customer specific facilities charges for large customers; in particular, NPC will complete the necessary analysis for SNWA's Hacienda facilities no later than the next general rate proceeding.

C. Multi-Tier Residential Rates

NPC's Position

550. Ms. Lipparelli stated that NPC eliminated the multi-tier Base Tariff Energy Rate because the consumers found it confusing. (Exhibit 98 at p. 8.)

Staff's Position

551. Staff proposed that the Commission adopt a two-tier rate structure for residential and small commercial classes as a means to encourage conservation. Ms. Bellard proposed to establish the first tier, "basic requirements", at the level equivalent to most residential customers winter usage since this period tends to exclude heavy air-conditioning usage. Based upon bill frequency information, Ms. Bellard set the first tier for the multi-family residential class and the single residential class at 600 kWh and 950 kWh. Staff asserted that its proposed residential first tier levels represents 71 percent of the total single family monthly winter bills and 72 percent of the total multi-family monthly winter bills. Due to an unworkable computer file, Staff set the small commercial class first tier equal to the single family residential tier in its development of

the pertinent rates, and acknowledged that if consumption is significantly different, rates would need to be recalculated. (Exhibit 106 at p. 7-8, Atch AMB-8, and Tr. at p. 1421 and 1422.)

552. As to pricing the second tier, Staff proposed that the BTGR be 110 percent of the first tier, and the BTER be 150 percent of the first tier, which recognized that fuel costs increase as usage increases. Staff's pricing proposal is based upon the professional judgment that the BTGR rate increase was set at a lower level than the BTER in order to not place NPC at risk for not collecting its revenue requirement. (Exhibit 106 at p. 9, Atch AMB-8 and Tr. at p. 1414-1415)

553. Staff opined that it was not the tier rate design that confused the customers but the "appearance of "double billing" due to NPC listing each rate component separately on the bill. (Exhibit 106 at p. 9.)

<u>BCP's Position</u>

554. Mr. Marcus for the BCP recommended a simple two-tier rate structure with the second tier applicable to all usage above 675 kWh per month. The second tier commodity rate should be 15 percent, or about one cent, higher than the first tier. Mr. Marcus stated that retention of the multi-tier rate design enhances conservation, is moderate, and achieves the rate continuity objective of limiting large increases and decreases. (Exhibit 114 at p. 56-57, Atch WBM-5.)

<u>NPC's Rebuttal Position</u>

555. NPC cited the following rationale as to why it is proposing to eliminate the multi-tier rate structure: 1) Customers find them difficult to understand; 2) Emergency conditions that lead to their creation have changed; 3) Tier rate structures inherently result in subsidies and inequities among customers; 4) Further research has indicated that such structures hurt as many, if not, more lower income customers than they benefit; and 5) Other mechanisms exist that can better meet the intended goals (e.g., Universal Energy Charge and Time of-Use rates). (Exhibit 117 at p. 41.)

556. NPC opined that Staff's proposed two-tier rate structure is an imprecise mechanism to achieve the stated goals of conservation and cost reduction, and that these goals would be better served by implementing time-of-use rates. NPC contended that an inclining block rate structure was not cost based, since it was based upon a single month's consumption, rather than on season and time-of-use, which are the primary causes for higher energy costs. Further, NPC stated that the process may increase costs by encouraging conservation during off-

peak periods when energy costs are lower, thus increasing the overall system energy costs. Additionally, NPC hypothesized that the lower first block rate may encourage consumption by consumers whose monthly usage has historically been less than the first tier. (Id. at 42-44 and Tr. at p. 1599-1600.)

557. Regarding less affluent customers, NPC referred the Commission to Docket No. 2357, in which the Commission had considered and rejected life line rates. Lifeline rates are similar to a two-tier inclining block rate structure. These rates were rejected on the basis that the evidence presented in that proceeding either questioned the assumption that low-income consumers use less energy or refuted it. (Id. at 44-45.)

558. NPC stated it had received a significant number of complaints from customers, including low-income customers, expressing concerns about continued high second tier usage even with conservation. (Id. at 46-47, Atch LIL-REB-12.) Further, NPC expressed several technical concerns about Staff's proposal: no support for the tier price differentials; tiered BTER rates are not calculated using recorded sales as done in the Deferred Energy Case (although the wrong column in the bill frequency analysis was used to develop the tier levels, use of the correct column does not materially affect the percentage of residential customers' winter usage being covered by the first tier); and the average small commercial monthly use is significantly less than 950 kWh. (Id. at 50-51, Atch LIL-REB-13 and Tr. at p. 1601-1602.)

559. NPC stated its criticisms of Staff's proposal are also applicable to the BCP's proposal. NPC offered the following additional criticisms of the BCP's proposal:

- BCP inappropriately applied the same first tier level to both multi-family and single family residential customers;
- BCP did not update the threshold to reflect the certification bill frequency information; and
- while recognizing the conditions that created the current tier system are abating, BCP proposed to perpetuate and expand this less efficient and equitable rate structure.

NPC observed that BCP's failure to recognize that a single-family residence uses more electricity than a multi-family home could result in the average single-family residential customer, which uses 2,000 kWh in July and August, to have 1,350 kWh in the second tier. NPC fears many of these individuals are low-income customers. (Id. at 51 and 523.)

560. During clarification questioning by the Commission, Ms. Lipparelli indicated a need to balance the first tier cutoff and the price differential with the potential effect upon low-income customers. She was also concerned about the ability of the utility to earn its revenue requirement. Ms. Lipparelli stated that the current 1.4 cent price differential, or BCP's proposed differential, which is closer to the California baseline rate differential of one cent, are more appropriate than Staff's proposed 2.5 cents per kWh. (Tr. at p. 1610-1611.)

Commission Discussion and Findings

561. While the Commission agrees with NPC that time-of-use meters and rates would be superior in achieving the goals of conservation and system cost reduction, a properly designed tiered rate structure is a reasonable methodology to use to obtain conservation and system cost reduction if time-of-use service is not available. While time-of-use rates directly reflect both time of use and season, the two primary drivers of energy cost, the tiered rate indirectly incorporates these energy cost drivers. First, the tier levels could be established to recognize seasonal consumption, thus directly incorporating the seasonality affect upon energy prices. Second, assuming that the highest priced energy is consumed at the end of the billing period, the consumer could act to minimize consumption during peak periods. NPC's residential customers' summer cooling requirements would be accurately portrayed as the consumption being billed at the higher energy price.

562. Staff's proposed tier structure is a well conceived and fundamentally sound proposal. However, it suffers from one weakness, Staff did not provide sufficient justification as to its proposed tier price differentials.

563. While the weakness in Staff's proposal is correctable, the Commission is concerned that use of a tier rate structure at a time of historically high energy rates will exacerbate the current historically high energy prices that the consumers are already paying during the high usage summer months, thereby creating a financial hardship for these customers. During the high usage summer months, the overall higher rate and the unavoidable higher usage due to high temperatures creates sufficient incentive to conserve. Therefore, the Commission finds NPC's flat rate proposal reasonable and approved.

D. Residential Time of Use Rates

NPC's Position

564. Due to the magnitude of the general rate case in combination with the Deferred Energy Application, NPC determined it was appropriate to offer the residential and small

commercial class another mechanism to conserve energy during peak times. Ms. Meacham for NPC stated that the time-of-use rates are cost based rates, and were developed using these classes time of use marginal costs plus an adder for the incremental cost of the meter. (Exhibit 101 at p. 9.)

565. Gene Williams, witness for NPC, stated that the proposed optional time-of-use tariffs cap the conversion to the optional time-of-use service at 1,000 customers for all such optional service. Mr. Williams stated the 1,000 per month cap was based upon NPC's estimate as to the number of meters they could retrofit. (Exhibit 105 at p. 2 and Tr. at p. 1385-1386.)

566. Upon Commission questioning, Mr. Williams stated that NPC had a plan to communicate the availability of the time-of-use meter program, but he does not know the details nor is he aware of any plan to market the service to new construction. (Tr. at p. 1385-1387.)

<u>Staff's Position</u>

567. Staff recommended that the Commission reject NPC's proposed time-of-use rates and require NPC to refile the tariffs with the appropriate corresponding data and load research by October 1, 2002. Staff's cited as it rationale its opinion that NPC provided insufficient information justifying the proposed rates. Staff acknowledged that it never requested the information it now believes necessary to evaluate the proposed rates. (Exhibit 106 at p. 10-11 and Tr. at p. 1423.) Further, Staff opined that significant differentials must exist between on-peak and off-peak periods to generate any system benefits. (Exhibit 106 at p. 11 and Tr. at 1424.)

568. During Commission questioning, Staff's witness Ms. Bellard stated, in addition to the BTGR rate differential, the BTER effects associated with the time-of-use program need to be evaluated in order to derive the impact upon system costs. (Tr. at p. 1424.)

<u>NEBG's Position</u>

569. Witness for the NEBG, Mr. Gildersleeve, stated that it should be a goal of NPC to replace an existing non-time-of-use meter with a time-of-use meter, and that NPC's proposed restriction on the number of customers that may elect time-of-use service should be eliminated. (Exhibit 111 at p. 5.)

<u>NPC's Rebuttal Position</u>

570. NPC reiterated its recommendation for the adoption of its proposed optional time-of-use rates for both the residential and small commercial customer class as this service is an

efficient and direct means of achieving the goals of conservation cited by the proponents for tiered rates. (Exhibit 117 at p. 53.)

Commission Discussion and Findings

571. A review of the proposed optional time-of-used tariffs contained in the Certification Filing disclosed that a significant BTGR rate differential exists between on-peak and off-peak consumption, with the on-peak price differential at approximately 7.5 cents per kWh for the residential service and 7 cents per kWh for small commercial service, while in all three tariffs the off-peak BTGR rate is less than 1.5 cents per kWh.

572. No Party to this portion of the proceeding provided any evidence indicating that NPC's proposed optional time-of-use general rates were not cost based.

573. Implementation of an optional time-of-use service would allow residential and small commercial customers a mechanism to conserve energy during peak times and serve as an efficient and direct means of achieving the goals of conservation cited by the proponents for tiered rates. BTER time-of-use pricing is a deferred energy rate design issue and has been raised by various parties (e.g., NCCEU's witness Dr. Berry) in NPC's current Deferred Energy Application (Docket No. 01-11029). The Commission's decision in that proceeding would be applicable to these optional time-of-use tariffs.

574. The Commissions finds that NPC's proposed optional residential and small commercial time-of-use tariffs are reasonable and approved for the time being. However, NPC should refile the tariff with the Commission, using the considerations raised by Staff at the hearing, no later than November 1, 2002. Further, the Commission encourages NPC, in addition to its retrofitting program, to market the service to new construction and pursue eliminating the 1,000 per month cap on retrofits.

E. Schedule LGS-WP and LGS-X-WP Rates

NPC's Position

575. NPC established the rates for these optional service tariffs equal to those for the otherwise applicable class. NPC witness Ms. Meacham explained that due to the fact that customers under these optional service tariffs were only assessed demand charges, NPC did not have billing determinants for an entire year. Thus marginal costs for this class could not be calculated. (Exhibit 101 at p. 9-10.)

576. During cross-examination by SNWA's attorney, NPC's witness Ms. Lipparelli concurred that NPC did calculate a separate marginal cost for the energy portion of the rates for

the LGS and LGS-WP customer classes. Ms. Meacham confirmed NPC did not use this information in the development of rates. (Tr. at p. 1347-1348.)

SNWA's Position

577. SNWA's witness Dr. Peseau recommended that the Commission require NPC to establish rates for its water pumping customers under schedules LGS-WP and LGS-X-WP based upon the marginal cost study for these customers, various "purveyors" and water districts, rather than charging another LGS class's higher rates to these customer classes. Dr. Peseau asserted that these customers are subject to unreasonable burdensome and discriminatory rates since these rates do not reflect these customers' profile, including: cost of service, load profiles, and interruptibility provisions. (Exhibit 108 at p. 4-7.)

578. Dr. Peseau estimated these customer classes are being charged $2,645,340 more than that supported by NPC's cost of service study. This was derived by comparing the annual revenue requirement allocated to these classes, to that allocable per NPC's marginal cost of service study ($17,814,000 versus $15,168,660). (Id. at 8-10, Atch DEP-1-DEP-4.)

579. Dr. Peseau stated, with the rate rebalancing adjustment, that the excessive allocated revenue requirement is reallocated only among the other LGS customer classes. (Id. at 11-13, Atch DEP-5.)

NPC's Rebuttal Position

580. Ms. Lipparelli stated NPC's proposed rate proposal, with the exception that the LGS-WP class energy BTGR rate was lower than the otherwise applicable class, is a continuation of the methodology approved by the Commission in Docket No. 96-7020. Further, Ms. Lipparelli stated that these customer classes' load profiles include curtailment periods, and, if the customer does not curtail in the future as contemplated by the rate, the rate would provide an inappropriate price signal. NPC has no control over whether a customer will curtail or not, and noted that there is no real penalty for not curtailing. (Exhibit 117 at p. 54-55 and Tr. at 1551.)

581. Ms. Lipparelli calculated, assuming no rate rebalancing, the impact associated with SNWA's proposal upon residential customer classes to be $4.2 million. (Exhibit 117 at 57)

582. During Commission questioning, Ms. Lipparelli clarified that while the marginal energy cost for this class is lower due to curtailments, NPC proposes to charge the higher otherwise applicable customer class energy rate as a means to reduce any incentive not to curtail.

Further, while NPC has no indication that these customers will not curtail in the future, history indicates that on occasion the customers do not curtail. (Tr. at p. 1612.)

Commission Discussion and Findings

583. NPC's marginal cost of service study included separate base general rate energy related information for schedules LGS-WP and LGS-X-WP, but NPC did not use this information to develop separate rates. Due to curtailments, the rates proposed would be lower that that for the otherwise applicable tariff.

584. NPC did not develop separate schedules LGS-WP and LGS-X-WP on the basis that this methodology is similar to that approved by the Commission in Docket No. 96-7020 and that it mitigates any incentive not to curtail when requested. NPC has no indication that these customers will not curtail in the future.

585. The Commission finds that the proposal of the SNWA to base the schedule LGS-WP and LGS-X-WP classes' energy BTGRs upon the marginal cost study and not the classes' otherwise applicable rates is reasonable and approved.

F. Demand-Related Costs in LGS Classes Demand Rates

NPC's Position

586. NPC's witness Ms. Meacham stated that implementation of total cost based rates would result in severe rate shock for the time-of-use classes. For example, the LGS customer classes' on peak and mid-peak demand charges would be 50 percent greater than current rates. Therefore, NPC proposed to mitigate the impact by gradually moving towards cost based rates. Ms Meacham noted that a gradual approach would both mitigate the customers' inability to plan for energy costs and enable NPC to avoid revenue instability by limiting the shifting of winter revenue to the summer. (Exhibit 101 at p. 6-8.)

NCCEU's Position

587. NCCEU proposed that all demand-related (i.e., transmission and generation) costs associated with the LGS customer classes should be recovered through the demand charge and not through the BTGR, since recovery of a fixed cost by a volumetric rate sends an incorrect price signal. NCCEU's witness Dr. Berry stated that two-thirds of the transmission and generation costs are recovered through the BTGR. Dr. Berry asserted that the reclassification of these costs would eliminate the need for a BTGR for all these classes. (Exhibit 112 at 13-16)

588. Regarding the LGS-1 class, Dr. Berry stated that even though the LGS-1 class does not have meters capable of measuring demand, these costs could be recovered by

establishing seasonally differentiated cost based demand charges. However, due to the significant shift in costs, Dr. Berry recommended that the reclassification for the LGS-1 customer class shift be delayed until 2004 when the final order in the next general rate proceeding would be issued. (Id.)

Commission Discussion and Findings

589. NPC's proposed gradual approach to cost based rates for the LGS classes is reasonable for the reasons cited by NPC. Therefore, the Commission finds NPC's rate treatment of demand related costs for LGS customer classes to be appropriate.

G. Standby Service Rate

NEBG's Position

590. Mr. Gildersleeve, witness for NEBG, stated that while NPC's Standby Service tariff rates are set at the applicable LGS-3/S/P/T tariff rates, these rates will "discourage on-site generation, which should be encouraged as an efficient way to provide cost effective distribution grid support." Mr. Gildersleeve proposed that a better rate design would be the "charging of the highest incremental cost of generation and/or purchased power during the time of stand-by service deliveries plus the TOU-specific BTGR." Further, Mr. Gildersleeve asserted that the facilities charge should be non-applicable as no facilities are used to serve this customer. (Exhibit 111 at p. 6-7.)

Commission Discussion and Findings

591. NEBG did not provide any evidence supporting its assertion that the current rate design methodology is inappropriate; therefore, the Commission finds NPC's proposed Standby Service tariff rate design reasonable and approved.

VII. Tariff Issues

A. Distribution Only Service Tariff

NPC's Position

592. During questioning, NPC's witness Mr. Williams stated that since the Open Access Transmission Tariff load-profiling option was developed in conjunction with the California restructuring, and is limited to California customers, there is no requirement in the State of Nevada to load profile. (Tr. at p. 1367, 1368, 1376, 1378, 1379, and 1383.)

593. During Commission questioning, Mr. Williams further stated that the cost of load profiling would be borne the utility's remaining customers, as no provision existed to recover the costs from a specific set of customers. (Tr. at p. 1384.)

CRC's Position

594. CRC proposed that several changes be made to NPC's proposed Distribution-Only Service tariff. CRC cites the following as the most significant proposed modifications: Rule No. 1 needs to cite the CRC as an eligible customer; Rule No. 3 application process is vague, and needs clarification, and the available interval meter requirement should be eliminated; and Rule No. 16 interval meter requirement for all customers should be modified to coordinate the requirement with NPC's Open Access Transmission Tariff. CRC's witness Gail Bates elaborated that the function of an interval meter was more related to transmission service than distribution service, and should incorporate FERC's requirements. Ms. Bates asserted that NPC's Open Access Transmission Tariff contained a requirement that interval meters were required on all loads of 50 kW or greater and load profiling was allowed for customers with demand less than 50 kW. (Exhibit 107 at p. 3-7 and Atch GAB-2-GAB-5.)

NPC's Rebuttal Position

595. In response to CRC's witness Ms. Bates testimony, NPC proposed several modifications to the proposed Distribution-Only tariff; however, it did not change the interval meter requirement. Mr. Williams stated that the interval metering, which allows hourly settlements, was a requirement placed upon AB 661 customers and should be applied consistently to SB 211 customers. Further, Mr. Williams explained that load profiling, in the context of restructuring, refers to modeling loads too small for demand metering. While Nevada was studying load profiling under the restructuring, the authorizing restructuring statutes were repealed. Thus, profiling was not provided for by regulation or under the Open Access Transmission Tariff. (Exhibit 122 at p. 2-5 and Atch GW-1.)

596. During cross-examination by the CRC, at which time the CRC expressed its support for the proposed changes, Mr. Williams clarified that, while not specifically stated by name, CRC meets the definition of an eligible customer in accordance with the revised proposed definition which included reference to a NRS 704.787 authorized entity. (Tr. at p. 1626-1627.)

597. During cross-examination by NEBG, Mr. Williams concurred that the requirement for the customer to pay their load ratio share of any deferred energy balance still existed, and that the proposed agreement's Exhibit B did not contain a description of the methodology because it had not yet been developed. (Tr. at p. 1628.)

//

//

Commission Discussion and Findings

598. CRC concurs with NPC's revised Distribution-Only tariff language. However, based upon the CRC's testimony, though the CRC was not specifically cited as exempt, one presumes the CRC continued its disagreement with the interval meter requirement. The load profiling costs would be borne by the utilities' remaining customers.

599. The State of Nevada has no profiling regulation, and NPC's Open Access Transmission Tariff load profiling is limited to California. NPC has not developed the deferred energy load ratio provision of the proposed tariff.

600. Based upon the forgoing, the Commission finds NPC's proposed Distribution – Only tariff reasonable and approved, and supersedes NPC's Electric Tariff No. 3, which is hereby canceled. NPC is required to file a completed Exhibit B to the agreement setting forth the methodology to be used to develop the customer's load ratio share of any deferred energy balance.

B. Equalized Billing-Budget Billing Program

NCCEU's Position

601. Dr. Berry, witness for NCCEU, recommended that the customers taking service under schedules GS and LGS-1 be allowed to participate in NPC's "Equalized Billing-Budget Billing Program". (Exhibit 112 at p. 12.)

NPC's Rebuttal Position

602. Mr. Williams stated that NPC's "Equalized Billing-Budget Billing Program" described in Section E to Rule No. 5 of its tariffs complied with NAC 704.338. Further, Mr. Williams stated that if NCCEU desired to change the regulations' parameters, then the issue could be raised in the Commission's investigation into revising the "Consumer Bill of Rights (NAC 704.302 to 704.390)", Docket No. 01-3015. (Id. at 6-7.)

Commission Discussion and Findings

603. NPC is correct that the issue would be better addressed in the Commission's open rulemaking proceeding, Docket No. 01-3015, and not in this proceeding. Therefore, the Commission finds NCCEU's request should be rejected.+

C. Very Large Single Family Residential Customers

NPC's Position

604. Ms. Lipparelli stated NPC's proposed creation of a separate multi-family residential rate class was the first step, and the largest step, towards separating the residential

customer class into various customer classes in recognition of differences in costs to serve different segments of residential customers. Further, Ms. Lipparelli stated that, due to the cost differential, NPC might propose in the future to create a large single-family customer class for those very large single-family homes that generally have three-phase service instead of single phase. (Tr. at p. 1317-1320.)

Staff 's Position

605. Ms. Bellard stated that a review of NPC's bill frequency report indicated there are a considerable number of residential customers which use over 50,000 kilowatt hours per month. (Tr. at p. 1419.)

BCP's Position

606. Mr. Marcus stated in order to develop a separate customer class for those single-family residential customers using 200 percent or 250 percent more than an average single-family residential customer; one would need to perform an analysis similar to that performed by NPC to create the multi-family residential customer class. (Tr. at p. 1520-1522.)

Commission Discussion and Findings

607. NPC's proposed creation of a separate multi-family residential rate class was the first step, and the largest step, towards separating the residential customer class into various customer classes in recognition of differences in costs to serve various segments of residential customers.

608. NPC acknowledged that a cost of service differential exists in servicing a large single-family home compared with the average single-family home. Staff observed that there are a considerable number of residential customers that use over 50,000 kilowatt-hours per month.

609. The Commission finds that NPC should propose the creation of a large single-family residential customer class in its next general rate change application.

VII. Summary of Findings

610. A summary of the Commission's findings in Docket No. 01-10001, Nevada Power Company's General Rate Case application, as outlined above, are as follows:

* The capital structure proposed by NPC, adjusted for the cost of Customer Deposits at 1.765 percent and excluding the Cost of Common Equity, is approved.

* A 10.1 percent return on equity is approved. This combined with the accepted capital structure, results in a rate of return of 8.37 percent.

* Staff's Mohave adjustment is approved and $185,000 is removed from NPC's revenue requirement.

* An interest synchronization adjustment is appropriate in the income taxes true up to synchronize the approved rate base to the approved weighted costs of capital. The actual calculation is based on the Commission's determination of the appropriate rate base.

* The mill tax rate is 4.0 mills.

* The ratio methodology approach is the proper way to calculate the uncollectible expense.

* Staff's adjustment to increase accumulated depreciation by $6,672,000, for the new depreciation rates on transmission, distribution and general plant, as was approved by the Commission in Docket No. 99-4006, is approved.

* NPC's accumulated SO2 allowances balance of $9,569,000 is approved and will be credited against NPC's rate base. The SO2 allowances balance will be amortized over a three-year period at $5,221,000 per year and will be amortized starting with the effective date of this Order.

* BCP's leasing revenues adjustment is approved

* Staff's leasing expenses adjustment of a $257,000 decrease in NPC's expenses is approved.

* Staff's Cash Working Capital adjustment to reduce rate base by $8,959,000 is approved.

* NPC's CIS system is placed into rate base.

* Staff's Other Rate Base deductions outlined in NPC's Closing Brief Regarding Revenue Requirement Issues totaling $8,892,000, are approved.

* The BCP's normalization adjustment of $1,108,000 for the Aquila transaction is rejected.

* The BCP's adjustment of a $217,000 reduction to rate base to annualize the fuel inventories at Harry Allen and Sunrise Stations is approved.

* Staff's Intangible Amortization reduction to expenses of $1,181,000 is approved.

* NPC's adjustments for MPAT and BU STIP are approved.

* NPC's performance bonus program, normalized at $300,000 per year on a going-forward basis, is approved.

* The $91,000 correction of the transfer error in Employee Benefits is approved.

* MGM's adjustment to remove $895,000 of SERP from NPC's expenses is approved.

* The Staff's reduction in advertising expenses of $84,433, and NPC's subsequent increase in expenses of $59,175were both rejected.

* Staff's $24,119 reduction to advertising expense is approved.

* NPC's request for $139,000 for injuries and damages is approved.

* The Staff's reduction in expenses of $920,332, and NPC's subsequent increase in expenses of $1,391,541, is rejected.

* Staff's adjustments of $1,226,000 for amortization of expenditures over two years and of $163,000 for the removal and capitalization of certain expenses from the test year is approved.

* Deferral of part of the Harry Allen site to Plant Held for Future use is appropriate as set forth in Attachment 1.

* Staff's overaccrued AFUDC adjustment to remove $519,000 from rate base is approved.

* Staff's schedule N-3 intercompany costs adjustment of $6,966,000 is not approved.

* NPC's 20-year weather normalization adjustment is approved.

* BCP's CIAC adjustment of $1,148,000 to increase revenues is approved.

* BCP's annualized late charge revenues adjustment of $756,000 is approved.

* BCP's transmission revenue credit adjustment of $1,176,000 is approved.

* BCP's executive pay adjustment is approved to reduce expenses by $159,000.

* The BCP's and Staff's Coyote Springs Water Rights adjustments are approved as set forth in Attachment 1.

* NPC's two-year amortization of the stock issuance expenses is the proper and reasonable way to handle these costs.

* NPC's calculation for the BTGR capacity shift is correct.

* NPC's test year restructuring costs of $768,000 are approved. Prior period restructuring costs will not be recovered.

* NPC's $2.063 million of Customer Transaction Software costs have been properly accounted for and should remain in CWIP accruing AFUDC until the system is developed and ready for Plant-In-Service.

* No determination has been made as to the prudence of any of the transaction, transition or goodwill costs at this time for the merger between SPPC and NPC. Instead, such costs are to be maintained in a deferred account without carrying costs until NPC files a general rate case with a test year ending on or after December 31, 2002.

* The divestiture costs shall be deferred as a regulatory asset, with a carrying cost.

* The correction of the allocation ratio number five in the unbundling study is accepted as it increases the accuracy of the study.

* NPC's proposed allocation of the regulatory expenses, other than the mill assessment, in the same manner afforded other administrative and general expenses is approved.

* NPC's direct assignment of restructuring costs to the distribution function is approved.

* The BCP's proposal to allocate the Las Vegas Franchise prepayment account to the functions based upon revenues is approved.

* All restructuring costs allowable in this Order shall be apportioned to the distribution function revenue requirement for only the following customer classes: LGS-3, LGS-X, LGS-WP-3, LGS-X-WP, SL, MSL-P, and MSL-C. However, due to the eligible governmental entity requirement being one-megawatt in the entire service area rather than one location, and the marginal cost study not containing information on a subclass basis, the listed classes may not encompass all the potential governmental customers.

* NPC's proposed full functionalization of its marginal cost study is approved.

* NPC's proposed marginal generation costs are approved.

* NPC's marginal energy costs are approved.

* NPC's marginal cost study appropriately accounted for the Hoover B benefit; however, in order to have a proper comparison the Hoover B benefit used in the marginal cost study shall be adjusted to its marginal cost value.

* NPC's marginal customer facilities charge is approved.

* NPC's revised allocation of the transmission expenses among distribution expense accounts is approved.

* NPC will commence tracking costs associated with grid meters and classify the costs as a substation cost in its next general rate case.

* NPC's revised proposed methodology for allocating facilities O & M expenses between customer and demand is approved.

* The inclusion of uncollectible expenses in NPC's marginal cost of service study is approved.

* NPC's "Energy Efficiency" department expense amount included in the customer weighting study is reasonable.

* NPC's treatment of late payment fees is approved.

* NPC's treatment of Other Revenues, excluding late payment fees that were previously discussed, is approved. In future proceedings, NPC will be required to allocate Other Revenues associated with tariff services between customer classes based upon the customer classes' payment of the tariff service revenues to the extent reasonably possible.

* All additional movement of the residential customer classes towards cost based rates should be held in abeyance until NPC's next general rate proceeding, and all customer classes should share in an equal proportional manner the revenue requirement change authorized in this proceeding.

* Staff's proposed residential and small commercial classes' monthly distribution charge is approved.

* NPC's proposed monthly distribution charge methodology, except for residential and small commercial customer classes, is approved.

* NPC should continue to pursue its policy for the development of customer specific facilities charges for large customers; in particular, NPC will complete the necessary analysis for SNWA's Hacienda facilities no later than the next general rate proceeding.

* NPC's flat rate proposal for residential rates is approved.

* NPC's proposed optional residential and small commercial time-of-use tariff is reasonable and approved.

* The proposal of the SNWA to base the schedule LGS-WP and LGS-X-WP classes' energy BTGRs upon the marginal cost study and not the otherwise applicable classes' rates is approved.

* NPC's rate treatment of demand related costs for LGS customer classes is approved.

* NPC's proposed Standby Service tariff rate design is approved.

* NPC's proposed Distribution –Only tariff is approved, superseding NPC's Electric Tariff No. 3, which is hereby canceled. NPC is required to file a completed Exhibit B to the agreement setting forth the methodology to be used to develop the customer's load ratio share of any deferred energy balance.

* NCCEU's request regarding NPC's "Equalized Billing-Budget Billing Program is rejected.

* NPC should propose the creation of a large single-family residential customer class in its next general rate proceeding.

611. A summary of the Commission's findings in Docket No. 01-10002, Nevada Power Company's Depreciation Study application, as outlined above, are as follows:

* NPC's request to implement a revised depreciation rate for only computer equipment, and use the 1992 depreciation rates approved in Docket No. 91-5032 for the remaining accounts, is granted.

* NPC's proposed steam generation plant lives should be used in this depreciation study.

* NPC will file a new depreciation study in conjunction with its next general rate application.

* In this instance, NPC's inclusion of interim additions in the development of production plant depreciation rates is inappropriate and will be removed from the development of depreciation rates for these plant accounts.

* NPC will not apply an escalation factor in the development of production plant cost of removal.

* NPC's recommended negative 125% net salvage value for Account No. 369 is approved.

* Staff's recommended positive net salvage value of 3% for the development of the computer equipment depreciation rate is approved.

* Staff's recommended depreciation rate base adjustments are rejected.

612. A Summary of Earnings is attached hereto as Attachment 1, and incorporated herein by reference.

//

THEREFORE, based upon the foregoing findings of fact and conclusions of law, it is ORDERED that:

1. The application filed by Nevada Power Company, designated as Docket No. 01-10001, is GRANTED IN PART, and DENIED IN PART, as outlined in Paragraph 610 above.

2. The application filed by Nevada Power Company, designated as Docket No. 01-10002, is GRANTED IN PART, and DENIED IN PART, as outlined in Paragraph 611 above.

3. Nevada Power Company SHALL FILE an application with the Commission, relating to their changes to Rule 9 as discussed in Paragraph 18 above, within 120 days of the issuance of this Order.

4. Nevada Power Company shall refile its tariffs to reflect the findings contained in this Order, and Staff shall review the refiled tariffs for compliance with this Order prior to the tariffs' acceptance.

5. This Order shall be effective on March 29, 2002.

6. The Commission retains jurisdiction for the purpose of correcting any errors that may have occurred in the drafting or issuance of this Order.

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

//

7. All arguments of the parties raised in these proceedings, including but not limited to arguments raised in the hearing, not expressly considered herein have been considered and either rejected or found to be non-essential further support for this Order.

By the Commission,

____
DONALD L. SODERBERG, Chairman and
Presiding Officer

____
RICHARD M. MCINTIRE, Commissioner

____
ADRIANA ESCOBAR CHANOS, Commissioner

Attest: _______________________________________
CRYSTAL JACKSON, Commission Secretary

Dated: Carson City, Nevada

______3/29/02___________

(SEAL)