BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA


Application of SIERRA PACIFIC POWER COMPANY for approval of the Thirteenth Amendment to its 2005-2024 Integrated Resource Plan, for approval of the Energy Supply Plan Update for 2007 and for a determination that the elements of the Energy Supply Plan are prudent. Docket No. 06-07010

At a general session of the Public Utilities Commission of Nevada, held at its offices on November 8, 2006.

PRESENT: Chairman Donald L. Soderberg
Commissioner Jo Ann P. Kelly
Commissioner Rebecca D. Wagner
Commission Secretary Crystal Jackson

ORDER

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

I. **Procedural History**

1. On June 30, 2006, Nevada Power Company ("NPC") filed with the Commission an Application, designated as Docket No. 06-06051, for approval of its 2007-2026 Integrated Resource Plan ("IRP").

2. On July 14, 2006, Sierra Pacific Power Company ("SPPC") filed an Application with the Commission, designated as Docket No. 06-07010, for approval of the Thirteenth Amendment to its 2005-2024 Integrated Resource Plan and Energy Supply Plan Update for 2007. SPPC concurrently filed a motion to consolidate the hearing in this docket with the hearing in Docket No. 06-06051.

3. The 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 704.736 et seq., NAC 704.9005 et seq., and NAC 704.9506.
DOCUMENT REVIEW AND APPROVAL ROUTING

DRAFTED BY: Cassandra C.

FINAL DRAFT ON 11/9/06 AT ___ M

REVIEWED & APPROVED BY: DATE

☐ ADMIN/ASST. ( ) 11/9/06

☐ COMM/CONSEL. 11/9/06

☐ SECRETARY/ASST. SEC. 

☐ OTHER ( )
4. The Commission has issued a public notice of the above-referenced Applications in accordance with state law and the Commission’s Rules of Practice and Procedure.

5. The Commission granted full or limited intervention to Southern Nevada Water Authority, Nevada Resort Association ("NRA"), MGM Mirage, City of Fallon, Mirant Americas ("Mirant") and Las Vegas Cogeneration ("LV Cogen"), White Pine Energy Associates ("WPEA") and Great Basin Transmission ("GBT"), Nevadans for Clean Affordable Reliable Energy ("NCARE"), and Washoe County Senior Law Project. The Commission denied Saguaro’s petition for leave to intervene. MGM, Mirant, and LV Cogen later withdrew their PLTIs.


7. On September 21, 2006, Staff filed a Motion to Strike the testimony of Mr. Pous.

8. On September 22, 2006, NPC and SPPC filed a Response in support of Staff’s Motion to Strike.

9. On September 25, 2006, BCP filed a Response to Staff’s Motion to Strike.

10. On September 27, 2006, Staff filed a Reply to BCP’s Response to Staff’s Motion to Strike.

11. On October 2, 2006, NPC and SPPC filed a Motion to Reject BCP’s Brief or, in the Alternative, to allow the Parties to file Closing Briefs on All Issues.

12. On October 4, 2006, BCP filed a Response to NPC and SPPC’s Motion to Reject BCP’s Brief.

13. On October 5, 2006, the Commission issued an Order in these dockets accepting the Stipulation filed on September 20, 2006, approving the Energy Supply Plan in Docket No. 06-06051, and approving the Energy Supply Plan Update in Docket No. 06-07010. The Commission’s procedural history for Docket Nos. 06-06051 and 06-07010, through September 20, 2006, can be found in that Order.

14. On October 11, 2006, the Commission issued Procedural Order No. 14 granting NPC’s and SPPC’s Motion to Reject BCP’s Brief and denying NPC’s and SPPC’s Motion to allow the Parties to file Closing Briefs on All Issues.
15. The Commission held the duly-noticed hearing for remaining Phases II, III, and IV from September 25, 2006, through October 6, 2006. At the hearing, the Presiding Officer denied Staff's Motion to Strike the testimony of Mr. Pous. The Presiding Officer took official notice of the following: the "Report to the Governor of the State of Nevada from the Nevada Electric Energy Policy Committee," dated January 11, 2001, and the Commission's Orders in Docket Nos. 84-430, 03-7004, 04-6029, 04-6030, 05-6038, 05-8004, 06-03038, and 06-04018.

II. Phase II Issues: Phase One of the Ely Energy Center and Critical Facility Status

A. Request for Approval of the Ely Energy Center and for $300 Million for EEC Development Activities

NPC and SPPC Position

16. Roberto Denis, Corporate Senior Vice President of Energy Supply for Sierra Pacific Resources ("SPR"), Nevada Power Company ("NPC"), and Sierra Pacific Power Company ("SPPC") (NPC and SPPC, collectively referred to herein as "the Companies") summarized several important aspects of NPC's IRP and proposed three-year action plan. (Exhibit 17 at 1, 4.)

17. Mr. Denis indicated that NPC has established a set of objectives and strategies intended to improve long-term reliability and assurance of supply, reduce customers' costs, reduce exposure to price volatility, and provide greater long-term price certainty. NPC's strategies and objectives are consistent with the State's long-term energy policy. NPC's plan has the following objectives: 1) it reduces demand with an aggressive demand-side management ("DSM") program; 2) it increases the share of load being served with renewable resources; 3) it diversifies the fuel mix; 4) it reduces exposure to volatile wholesale markets; 5) it improves reliability; 6) it minimizes risks; and 7) it keeps costs at reasonable levels. (Id. at 9-11.)

18. Mr. Denis stated that the centerpiece of the Preferred Plan is the proposed Ely Energy Center ("EEC"), a 1,500 megawatt ("MW") supercritical clean coal generating facility to be located in White Pine County, Nevada. The first 750 MW generating unit is proposed to be in service in late 2011, with the second unit following by the summer of 2013. The output from the EEC is to be shared by NPC and SPPC and transmission projects that interconnect the EEC to NPC's and SPPC's systems will be required. A new North-South Intertie ("Intertie") will interconnect the EEC
to NPC's electric system and will connect, for the first time, NPC's and SPPC's systems. (Id. at 11.)

19. Mr. Denis stated that in order to perform the necessary resource planning analyses, the Companies allocated 80% of cost and benefits of the EEC and the Intertie to NPC and 20% to SPPC. This allocation was not based on any single factor, but represents an approximation, based on current conditions, of the future utilization of the EEC. The Companies intend to revisit the allocation as more detailed engineering and economic analysis is performed. This analysis will necessarily be based on updated load forecasts, as well as updated projections of the relative open positions and fuel mix at the two utilities. Current estimates of the cost to construct the EEC, including the Intertie, are in the range of $3.7 billion. (Id. at 12; Exhibit 20.)

20. Mr. Denis clarified that the Companies do not plan to build the first 1500 MW (two 750 MW units) of generation at the EEC in phases. Construction of the first two units will be staged so that the online dates are staggered, but the Companies intend to design and procure the equipment and construct the first two units (1,500 MW total capacity) as a single project. The economic analysis provided for the EEC in the filing is based upon a single procurement and a stated construction schedule. Phasing of the procurement or construction processes for the two units would necessarily result in increased costs, which are not reflected in the analysis. The Companies considered scenarios that included a delay of the second 750 MW unit, and provided a description of two of these scenarios and the construction cost impacts of them. These scenarios result in increased construction costs, loss of fuel savings, increased AFUDC, increased energy and capacity costs, and reduced reliability. (Exhibit 20 at 4-7.)

21. Mr. Denis explained that the estimated cost of the two 750 MW units was developed based on the following assumptions: 1) contracting for fabrication and equipment supply for two 750 MW units is performed once; 2) one set of common facilities will service both units; 3) as construction sequences on Unit 1 are completed, equipment is delivered and construction forces begin similar work on Unit 2; and 4) a “slide-along” design, whereby the units are a duplicate design, rather than a mirror image, allowing “lessons learned” on the first unit to be applied on the second unit. (Id. at 5-6.)
22. Mr. Denis stated that if the Commission grants full resource planning approval to construct two 750 MW units at the EEC, it will not lose the opportunity to review the timing of the second unit. The Commission will have an opportunity to consider the latest forecasts information in SPPC’s July 1, 2007 IRP filing, and again when the Companies present the detailed engineering, construction and cost estimates and refined project schedule in the filing to be made once the air permit is received in the spring of 2008. (Id. at 9.)

23. Mr. Denis stated that the Intertie, by providing a path to market, will aid in the development of renewable resources in eastern Nevada and that NPC has requested that 300 MW of network resources be designated to import renewable resources over the Intertie into NPC’s load center. The Intertie will also allow NPC and SPPC to share operating resources to benefit customers at both ends of the state. (Id. at 12.)

24. William Rogers, Treasurer of SPR, SPPC and NPC, supported the Financial Plan and supporting analysis included in Volume VI and Technical Appendix II, 2 of 3 in NPC’s IRP Application. (Exhibit 12 at 1-2; Exhibit 13 at 1-2.)

25. Mr. Rogers stated that NPC can finance its Preferred Plan or Alternative Plan by using internally generated funds, refinancing existing debt, issuing new debt, and issuing equity. NPC’s key assumptions for its financial analysis include: 1) ROE: 10.6% as set in SPPC’s last general rate case (“GRC”); 2) a target equity level of forty-three percent; 3) a new debt coupon rate of 7%; 4) a modest restoration of the dividend; 5) Commission approval of Critical Facility designation and requested ratemaking treatment; and 6) Non-fuel operation and maintenance (“O&M”) of 2% per annum escalation. (Id. at 2-3.)

26. Mr. Rogers stated that he did have some concerns regarding NPC’s ability to finance the Preferred Plan because the EEC and Intertie projects represent the largest construction projects undertaken by either NPC or SPPC. However, with Critical Facility designation and the requested ratemaking treatment, especially the recovery of Construction Work in Progress (“CWIP”) in rate base and an ROE enhancement, NPC expects to be able to support the contemplated debt and equity financings necessary to meet the construction schedule. (Id. at 3.)
27. Mr. Rogers stated that NPC will have adequate working capital to provide for the interim funding of the capital expenditures described in the Preferred Plan, and to continue to purchase fuel and power in the commodity markets provided that it receives timely and appropriate revisions to the BTER and timely recovery of its deferred energy balances. The financing plan will become more challenging if NPC's credit facility must be accessed to finance a large deferred energy balance. (Id. at 4.)

28. Mr. Rogers stated the NPC will need to raise equity capital in order to maintain and improve its credit ratings given the utilities' projected capital requirements. The Companies also need to demonstrate to the rating agencies that they are maintaining a constructive relationship with the Commission and its Staff. (Id. at 4.)

29. Mr. Rogers stated that it is reasonable and necessary to restore the dividend given the Companies' capital requirements as it will become necessary at some point during the construction cycle to pay a dividend in order to attract the necessary equity capital to fund construction. The proposed dividend payout ratio would be less than that of the average investor-owned utility. The Companies are not asking the Commission to remove current restrictions on the payment of a dividend but a dividend payout would be consistent with the Commission's current restrictions. (Id. at 5.)

30. Mr. Rogers explained that the details of the Companies' financial plan are subject to strict disclosure rules issued by the United States Securities and Exchange Commission and contain commercially sensitive material and are included in the confidential material submitted with the application. (Id. at 5.)

31. NPC witness, Charlie Pottey, Manager of Long Term Resource Planning for the Companies, provided testimony sponsoring Volume VI, Section 1 of the Supply Side Plan. He testified to the results of the economic analysis of the expansion plans that the Companies considered and the reasons that led to its selection of the Preferred Plan. (Exhibit 27 at 3; Exhibit 28 at 3.)

32. Mr. Pottey stated that the economic analysis measured the Present Worth of Revenue Requirements ("PWWR") of ten expansion plans, consisting of various generation additions over a
twenty-year planning period, which included the Companies' load forecast, purchased power price forecast, fuel price forecast and the capital cost and performance characteristics for the generation options that were considered. The expansion plans were evaluated using low, base and high fuel, purchase power and load forecasts. All economic analyses included the March 24, 2006, fuel and purchased power forecast and the production costs and capital revenue requirements for the analyses were calculated using PROMOD (production cost simulation software) and a CER (capital expense recovery) module. (Id. at 5-7.)

33. Mr. Pottey stated that the results of the economic analysis are included in the Economic Analysis Results section of Volume VI of the Resource Plan and the supporting detail is provided in the Supply Side Section of Technical Appendix II. (Id. at 8.)

34. Mr. Pottey stated that the Companies' Preferred Plan includes: i) the construction of 428 MW of "quick start" combustion turbines ("CTs") in 2008 and 214 MW of CTs in 2009 at the existing Clark Station; ii) the construction of Phase One of the EEC, two 750 MW supercritical coal units and associated transmission additions; and iii) the construction of the Intertie. (Id. at 9.)

35. Mr. Pottey stated that the Companies' Preferred Plan was selected because it provides the lowest cost and largest improvement in fuel diversity and system reliability over the greatest range of potential scenarios. Further, it has the greatest positive impact on fuel diversity, provides increased operating flexibility, improves system reliability, and allows NPC to comply with the renewable portfolio standard ("RPS"). The Preferred Plan is not the least cost plan but provides significant advantages over the least cost plan which includes less reliance on the volatile wholesale markets, reduced reliability risks, and greater operating flexibility. (Id. at 9-10.)

36. Mr. Pottey also provided a description of the Companies' Alternative Plan. This plan is similar to the Preferred Plan except in the Alternative Plan the EEC and Intertie are replaced with gas-fired combined cycle units in 2011 and 2013. The Alternative Plan has the lowest twenty-year PWRR under base fuel and purchased power scenario, but it does not have the lowest twenty-year PWRR under a high fuel and purchased power scenario. (Id. at 10-11.)

37. Mr. Pottey stated that there are additional considerations impacting the Companies' selection of the Preferred Plan over the Alternative Plan that include:
a) The major generation additions in the Alternative Plan are natural gas-fired and would increase the Companies' reliance on natural gas, increase the Companies' exposure to natural gas price volatility, and further decrease supply diversity; and

b) The Alternative plan does not include a transmission line interconnection between NPC's and SPPC's electric systems and, consequently, does not include either the strategic benefits (i.e., reliability, stability, and access to new renewable energy markets) of the Preferred Plan or the operational benefits that are anticipated to be possible once the two systems are electrically interconnected. (Id. at 13-14.)

38. In response to questions in cross examination regarding whether the Companies at any time considered the possibility that some combination of renewables might be able to supplant the necessity of unit one at the EEC, Mr. Pottey responded that he did not believe that this option would be practical. Complying with the RPS has been an aggressive and challenging undertaking and the Companies have had difficulty meeting these standards. (Tr. at 315.)

39. David Sims, Director of Project Development for NPC and SPPC, provided testimony supporting NPC's and SPPC's decision to seek approval to construct the EEC. (Exhibit 36 at 2; Exhibit 37 at 2.)

40. Mr. Sims described the major components of EEC project. The project will be developed in two phases. Phase 1 will include two 750 MW supercritical pulverized coal units with the first unit scheduled to be in operation in late 2011 and the second unit in operation in mid-2013. Phase 2 will include two 500 MW integrated gasification combined cycle facilities and would be installed after commercial viability of coal gasification technology had been demonstrated. It is estimated that this could occur in the 2016 to 2018 timeframe. (Id. at 4.)

41. Mr. Sims indicated that two potential sites for locating the EEC have been identified in Steptoe Valley. One site is approximately 15 miles north of Ely and the other site is approximately 50 miles north of Ely. Several conditions favor siting a facility within the Steptoe Valley including: availability of water resources; a supportive community and community leadership; existing rail right-of-way that provides access to main line rail service; existing highway infrastructure; a nearby approved utility transmission corridor; an existing community that can provide housing, services,
and utilities to the future workforce; proximate access to a transmission interconnection with SPPC’s transmission system; moreover, its location facilitates power transfers from renewable energy sources to both Companies. (Id. at 3-4.)

42. Mr. Sims stated that for analysis purposes only 80% of the construction costs for the EEC have been allocated to NPC and the remaining 20% have been allocated to SPPC. He indicated that, as described in the testimony of Roberto Denis and in the Memorandum of Understanding ("MOU"), the cost allocation will be revisited as more detailed engineering and economic analysis is performed. The Companies are in the process of developing a formal Project Development Agreement which will address approvals of budgets and capital expenditures, negotiation of commercial agreements governing the facilities, operation, maintenance and dispatch of the facilities, and reimbursement of capital and operating expenses by the participants. (Id. at 5-6, Attachment SIMS-2.)

43. Mr. Sims also explained that the details of the cost allocation for development activities (the initial expenses to develop the project) for which the Companies are seeking IRP approval in these dockets is contained in a MOU, which is attached to his testimony as Attachment SIMS-2. These costs will initially be split as follows: NPC will incur 80% of the costs and SPPC will incur the remaining 20%. The MOU indicates that a Joint Ownership agreement will be created for the Companies and that, if this agreement sets forth ownership interests that are different than the initial split, then the costs accounted for pursuant to the MOU will be adjusted so as to be consistent with the ownership interests set forth in the agreement. (Id. at 5, Attachment SIMS-2)

44. Mr. Sims stated that the supercritical boiler technology employed in the proposed EEC has several advantages over conventional coal units including increased efficiency and lower emissions. Supercritical boilers have demonstrated commercial success burning low-sulfur Powder River Basin ("PRB") coals which produce lower emissions of sulfur oxides and nitrogen oxides. (Id. at 7.)

45. Mr. Sims stated that EEC Project is in the "development phase" and that the following development activities are underway: air permitting; water rights acquisition; studies to assess the viability of various supercritical boiler and emissions control technologies, site constructability, and
requirements for temporary housing for the construction workforce; consultation with local and state government officials; land acquisition application; initial coordination with the Bureau of Land Management's ("BLM") for an Environmental Impact Statement; and railroad studies to support transportation of coal to the EEC.  (Id. at 9-10.)

46. Mr. Sims stated that the following major milestones must be faced by the EEC in the next two years:

<table>
<thead>
<tr>
<th>MILESTONE ACTIVITY</th>
<th>EXPECTED DATE OF COMPLETION</th>
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<tbody>
<tr>
<td>Submission of Air Permit to the NDEP</td>
<td>November 2006</td>
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<tr>
<td>Initial Notice to Proceed to Boiler Vendor</td>
<td>May 2007</td>
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<td>Draft Environmental Impact Statement</td>
<td>November 2007</td>
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<tr>
<td>Award of Final Air Permit by the NDEP</td>
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<td>Final Environmental Impact Statement</td>
<td>May 2008</td>
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<td>BLM Record of Decision</td>
<td>July 2008</td>
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<td>August 2008</td>
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<td>Boiler Steel Erection</td>
<td>Winter 2008</td>
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<tr>
<td>Commercial Operation of EEC Units 1 and 2</td>
<td>December 2011 and June 2013</td>
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</tbody>
</table>

NPC intends to move forward with all of the required development and permitting activities to ensure that the above milestones are achieved. The Companies anticipate that they will incur an additional $17 million during the balance of 2006 for a total of $20 million by the end of the year. These development costs will be split in accordance with the allocation procedure included in the MOU. (Id. at 12.)

47. Mr. Sims stated that during the three-year Action Plan period (2007-2009) of its 2006 Resource Plan, projected expenditures are $25 million for 2007, $523 million in 2008, and $1.1 billion in 2009. Of this amount, NPC is seeking Commission approval to commit up to $300
million through receipt of the BLM Record of Decision which is expected in July 2008. The $300 million will be used for development activities for the EEC. (Id. at 12.)

48. Mr. Sims stated that at some point during the first two quarters of 2008 the Companies will make a joint filing with the Commission in which they will provide their plan for engineering and construction, the detailed cost estimate and schedule for the project, and request approval to proceed with the balance of the project’s development. (Id. at 14-15.)

49. The Companies’ witness, David Harrison, Economist and Senior Vice President at NERA Economic Consulting (“NERA”), provided testimony regarding the environmental costs and the economic benefits of the ten expansion plans that were considered in NPC’s IRP and SPPC’s Thirteenth Amendment. The results of his analyses are included in Technical Appendix II to NPC’s IRP. (Exhibit 92 at 1, 5-6; Exhibit 93 at 1, 5-6.)

50. Dr. Harrison provided a summary of the overall methodology that he developed to assess the environmental costs of the expansion plans and summaries of the specific methods he used to estimate environmental costs for emission subject to and not subject to a cap-and-trade program. (Id. at 7-9.)

51. Dr. Harrison provided a summary of the results of his assessment of the environmental costs for the expansion plans in Table 1, “Present Value of Environmental Costs (millions of dollars), 2007-2026, for Sierra and Nevada Power Expansion Plans” of his testimony. Table 1 is reproduced below:

<table>
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<tr>
<th>Expansion Plan</th>
<th>NOₓ</th>
<th>VOC</th>
<th>PM</th>
<th>SO₂</th>
<th>Mercury</th>
<th>Environmental Costs without CO₂</th>
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Note: All values are present values as of January 1, 2007, in 2006 dollars.

52. Dr. Harrison stated that the environmental costs listed for carbon dioxide (“CO₂”) emissions are listed separately in Table 1 because of the speculative nature of CO₂ emission costs.
Table 1 provides the estimates of environmental cost related to CO₂ based upon the methodology that he used. (Id. at 10.)

53. With regard to the non-CO₂ environmental costs, Dr. Harrison stated that the present value of the environmental costs range from about $213 million to $245 million among the ten expansion plans. The environmental costs of the Preferred Plan (plan 11, about $224 million) are about $21 million less than the environmental cost of the Alternative Plan (Plan 13, about $245 million). (Id. at 11.)

54. With regard to the CO₂ environmental costs, he stated that they are considerably larger than the non-CO₂ environmental costs for all of the expansion plans. Differences among the plans generally are relatively small. The estimated CO₂ costs are about $2.4 billion for the Preferred Plan and about $2.2 billion for the Alternative Plan, a difference of about 8 percent. He noted the following uncertainties and caveats regarding these estimates:

a) The damage values relate to global damages rather than damage to Nevada residents;

b) The damage values are based upon an average of studies that differ considerably in their estimate and that are forced to make simplified assumptions to calculate global damages, and in some cases the simplifying assumptions tend to overstate damages;

c) The cost values assume that a specific U.S. cap-and-trade program for CO₂ will be put in place in 2010, which is of course highly speculative.

He concluded that for all of the reasons stated above, the environmental costs related to CO₂ emissions are highly uncertain. (Id. at 11-12.)

55. Dr. Harrison provided a summary of the sources of information he used to assess the “Economic Benefits” of the expansion plans and a summary of the measures he used to determine the “Economic Benefits.” (Id. at 12-13.)

56. Dr. Harrison provided a summary of the “Economic Benefits” results in Table 2. “Present Worth of ‘Economic Benefits,’ 2007-2026, for Sierra and Nevada Power Expansion Plans.” Table 2 is reproduced below:
Table 2. Present Worth of “Economic Benefits”, 2007-2026, for Nevada Power Company Expansion Plans

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Operation Effects in Nevada of Expansion Plans

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Combined Effects in Nevada of Expansion Plans

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Note: All dollar values are present values as of January 1, 2007.

57. With regard to the implications of the results in Table 2, Dr. Harrison stated that:

a) The “Industry Value Added” provides the most comprehensive measure of the economic impacts of the expansion plans;

b) As expected, the construction effects are smaller than the operation effects, which measure the effects of expenditures from the operation of all units and not just those related to the new units that are added in each plan;
c) The difference in industry value added between the Preferred Plan ($21.7 billion) and the Alternative Plan ($21.2 billion) is about $540 million;

d) There are larger relative differences in the construction cost impacts between the Preferred Plan ($4.1 billion) and the Alternative Plan ($2.2 billion);

e) The “Economic Benefits” are not comparable to social benefits and costs because they represent economic impacts in Nevada rather than social benefits of providing electricity to Nevada residents. (Id. at 14-15.)

58. In response to Commissioner Kelly’s request, Dr. Harrison provided a comparison of the emission rates expected for the proposed EEC unit and compared them to the emission rates for the existing coal units at Reid Gardner Generating Station. This information is provided in the table below. (Id. at 3.)

<table>
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<tr>
<th></th>
<th>( \text{SO}_2 ) (lb/MWh)</th>
<th>( \text{NO}_x ) (lb/MWh)</th>
<th>( \text{PM}_{10} ) (lb/MWh)</th>
<th>( \text{Hg} ) (lb/TWh)*</th>
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<td>0.545</td>
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Source: NERA calculations and data from NPC/SPPC.
Note: 1 Terawatt hour (TWh) is equal to 1,000,000 Megawatt hours (MWh).

59. Dr. Harrison provided an update regarding whether the recommendations made in the California Environmental Protection Agency Climate Action Team Executive Report to the Governor and the California Legislature in March 2006 have been accepted by the California Legislature, and whether any laws have been passed. He first provided a summary of the report and then indicated that California Assembly Bill (“A.B.”) 32, which will require the California Air Resources Board (“ARB”) to establish a statewide greenhouse gas emission limit to be achieved by 2020, was passed by the California Legislature on August 31, 2006, and is expected to be signed into law by Governor Schwarzenegger. The California Legislation authorizes, but does not require, the ARB to adopt market-based compliance mechanisms and to monitor compliance with any
market-based compliance mechanism that is adopted. He included a summary of the timeline for
development of market-based compliance mechanisms established by A.B. 32, provided a status
report of other state policies related to the market-based options recommended in the report and
indicated that no details on the potential market-based options have been developed. (Id. at 6-7.)

60. The Companies’ witness, John Lescenski, Manager of Generation Asset Performance
Management, provided information regarding the installation of supercritical coal generation
technology in North America in accordance with Commissioner Kelly’s request at the August 22,
2006 pre-hearing in this docket. (Exhibit 25 at 1-2; Exhibit 26 at 1-2.)

61. Mr. Lescenski stated that fifty-five units or approximately 40,000 MW of supercritical
pulverized coal plants have been built outside of North America since 1996. The predominant
supercritical boiler manufacturers for these units have been Alstom Power and Mitsubishi, but
Hitachi and Foster Wheeler have also built supercritical units. The first supercritical unit to be
constructed in North America since 1990 is the Genesee 3 unit located south of Edmonton, Canada.
This unit was approved by the Alberta Electric Utility Board in 2001, construction took
approximately 36 months and the unit began commercial operation in March 2005. (Id. at 3-4.)

62. He stated that four supercritical plants/units are currently under construction in the
United States and scheduled to be in commercial operation by 2009. (Id. at 5.)

63. The Companies’ witness, Joseph Brignola, Manager, Coal Procurement & Operations
for the Companies, provided testimony discussing the status of the coal supply and transportation
programs to support the EEC. (Exhibit 29; Exhibit 30.)

64. Mr. Brignola provided a list of the Companies’ objectives and challenges for the supply
and transportation of coal to the EEC and also provided the current status of the Companies’ coal
supply and transportation program for the EEC. The Companies intend to use PRB coal at the EEC
and have opened discussion with PRB suppliers and reviewed coal specifications with the EEC
design engineers. He noted that uncertainties exist regarding the ability of the railroads to transport
PRB coal to the EEC reliably and at reasonable rates, but that the Companies are working to resolve
these uncertainties. (Id. at 5-7.)
65. Mr. Brignola stated that the Companies have contacted the railroads concerning the EEC, and the railroads have undertaken studies to determine the scope, estimated cost, and timing of required improvements to their infrastructure. At this time, the Companies cannot project when they will have a proposal in hand from the railroads encompassing rates, service levels, railcar requirements and form of contract for the EEC. (Id. at 7.) In response to questions regarding when the Companies felt that they could get an executed contract with Union Pacific on what progress needs to made before this question can be answered, he replied that a positive result from the Companies' IRP application would allow the Companies to represent that they are moving forward with the EEC and this would help with obtaining a contract. (Tr. at 339.) Also, the railroads are reluctant and even unwilling to expend their resources on coal projects that they do not feel will come to fruition and there have already been a couple of false starts on a White Pine County coal project. (Tr. at 334.)

66. In response to cross-examination questions, Mr. Brignola stated that the Union Pacific is attempting to ensure that it can expand its system to meet the growing demand for PRB coal and it is making a commitment to the coal industry and the utility industry that it intends to support growth out of the PRB. (Tr. at 336.)

Staff Position

67. Staff witness, Jon Davis, Electrical Engineer, provided testimony addressing the Companies' requests related to the EEC. (Exhibit 52 at 1.)

68. Mr. Davis recommended that the Commission:

a) Deny the Companies' requests for approval of construction of Phase One of the EEC;

b) Approve the Companies' request to each make a filing subsequent to the receipt of the air permit for the EEC for approval of the remaining funds necessary for construction and operation of the EEC as amendments to the Companies' respective IRPs;

c) Approve up to $300 million requested by the Companies for development costs for the EEC, subject to the modifications listed in Attachment JDF-10;
d) Order the Companies not to spend the money listed in Attachment JFD-10 for 2008, until they have an approved air permit for the EEC, and they file amendments with the Commission for approval to expend the remaining funds to begin construction of the plant;

e) Order the Companies to hire a rail consultant to assist in negotiations with the Union Pacific railroad; and

f) Order the Companies to file a coal inventory study in a future amendment to their respective IRPs when seeking further approval for the EEC. This inventory study should consider the operational risks associated with rail supply to the EEC. (Id. at 2.)

69. Mr. Davis explained that Staff does not recommend that the Commission grant full resource planning approval of Phase One of the EEC at this time because the project as proposed by the Companies is not sufficiently defined to warrant resource planning approval of the EEC or its construction costs. However, the project is sufficiently defined to warrant approval of $300 million to initiate development, permitting, and procurement activities associated with the EEC, including initial studies associated with the transmission lines. There are several critical elements that need to be determined before the Commission grants resource planning approval for expenses beyond the $300 million for the construction phase of the EEC. These critical elements include:

a) An understanding of the transportation costs for hauling coal to the EEC including coal transport costs from the source of the coal to the EEC and the rehabilitation cost of the Northern Nevada Railroad. Coal transportation costs could constitute 40-50% of the total fuel, operating, and maintenance costs for the EEC;

b) Approval of the air permit for the EEC;

c) Permits for the transmission facilities that are required for the EEC; and

d) Other confidential critical elements. (Id. at 5-6, Confidential Attachments JDF-34-35.)

70. Mr. Davis also stated that the Companies' proposal also lacks the following:

a) Cash flows in all years of the projected construction of the plant;

b) Definitive fuel costs;
c) A current plant estimate based on a detailed engineering estimate. His concerns are heightened by the rise of commodity prices of the exotic materials that will be required for the boiler, environmental equipment, and turbine, and the estimate may be substantially higher than the Companies have estimated; and

d) A definitive plant site and water supply.

71. Mr. Davis stated that the Commission should approve the Companies' request to make a subsequent filing (an amendment to the IRP), which would then ask for approval for the remaining funds to construct the EEC. He indicated that the amendment should contain the following information:

a) A term sheet with the railroad supplier;

b) A final study on the coal source;

c) An approved air permit for the EEC;

d) Verifiable information that it has the necessary water rights approved by the Nevada State Engineer to operate the Station;

e) The necessary permits for the construction of the transmission line and substations;

f) A detailed analysis and support for the ownership share allocation of the plant and transmission line;

g) An update on the Environmental Cost and Economic Benefit Study for the EEC;

h) More precise input data for the estimated construction costs for the Phase One of the EEC and the coal transportation costs. (Id. at 7-9.)

72. Mr. Davis stated that the supercritical technology that the Companies will use in the EEC is not a new process and that there are about 400 supercritical boilers in operation today. The recently retired Mohave Generating Station employed supercritical technology. (Id. at 9-10.) Supercritical boilers offer energy efficiency and emission benefits over subcritical boiler technology. (Id. at 10.)

73. Mr. Davis indicated that it is doubtful that NPC could obtain air permits for subcritical boilers at the 750 MW size proposed because subcritical boilers are not the best available
technology for air pollution control for this type of application. Other coal generation technologies are in the experimental phase, and the Companies would be taking a substantial operating risk if they were to pursue any of these technologies. (Id. at 11.)

74. Mr. Davis explained that it is important that the Companies use proven coal generation technology at the EEC for the following reasons: 1) the facility will be a baseload plant and high capacity factor operation has the potential to save the Companies’ ratepayers in excess of $350 million per year when compared against the most efficient natural gas plant; and 2) the Companies’ experience with unproven technologies, namely Mohave and Pinon Pine plants, have cost the Companies and Nevada ratepayers millions of dollars. (Id., at 12.)

75. Mr. Davis stated that he agrees with the Companies’ assessment and use of PRB coal for the EEC. (Id., at 13.)

76. Mr. Davis stated that the Companies did review options other than a utility self-built plant. NPC did engage in negotiations with LS Power Associates, L.P. (“LS”) and Sithe Global Power, LLS (“Sithe”) for similar fired coal plants but that negotiations had been unsuccessful to date. (Id., at 14.)

77. Mr. Davis did not believe that the Commission should order the Companies to pursue Independent Power Producer (“IPP”) options before allowing them to expend development funds for the EEC. In order to fully evaluate the Companies’ proposed self-build options, the Companies must be allowed to spend some funds developing reliable cost data for their self-build option. Further, given the amount of energy that the EEC would provide, it would be unwise to have the fate of such an important resource left only to entities over which the Commission has little regulatory authority. IPPs do not have the same obligation to serve retail customers as the Companies as load-serving utilities. Also, it is also critical to have a utility self-build option against which to compare IPP proposals. (Id., at 14-15.)

78. In response to clarification questions regarding Mr. Davis’ experience with the issuance of a request for proposals (“RFP”) for long-term resources while he was employed by NPC, he indicated that the RFP process took approximately 15 months and was unsuccessful for securing long-term resources. (Tr. at 652-654.)
79. Mr. Davis stated that the Companies should continue to pursue other alternatives besides a self-build option. He explained that if other types of coal projects are in the best interest for their ratepayers, they should present these to the Commission as alternatives to the construction of the EEC in a subsequent amendment. (Id. at 15.)

80. Mr. Davis stated that of the $300 million that the Companies are requesting to spend from 2006-2008 for development activities related to the EEC as listed on Attachment JFD-2, they should be restricted by Commission order from spending the funds designated for 2008 until an air permit is granted for the EEC. Also, the Companies have indicated that once they obtain an air permit for the EEC, they will file amendments to their IRPs if they feel that the EEC is still the best option for the ratepayers. (Id. at 16.)

81. Mr. Davis stated that, in order to ensure an on-line date for the EEC of 2011, the following actions must be taken with respect to procurement of the boiler and turbine: 1) perform the necessary engineering for the boiler and turbine RFP; 2) issue the RFP for both the boiler and turbine; 3) evaluate and award the RFP to the appropriate vendor; and 4) release the boiler and turbine manufacturer for necessary engineering to manufacture the long lead-time components such as the generator forgings. The Companies will have to evaluate at the time they release the boiler and turbine manufacturer whether the $48 million that they anticipate spending for the long lead-time items prior to receiving an air permit is a prudent expenditure. The risk associated with making a commitment to release these funds prior to receiving the air permit include air permit risk, changes in load forecast, changes in air pollution regulations, and railroad contracting risks. To address these concerns he provided in Attachment JDF-10 a revised expenditure schedule for development activities related to the EEC. (Id. at 16-17, Attachment JDF-10.)

82. Mr. Davis stated that the Companies’ Preferred plan which includes the EEC is not a least cost plan. A plan that relies on economy energy (short term purchases) is the least cost plan. He is not recommending this plan because the 2006 Western Electricity Coordinating Council (“WECC”) Power Supply Study from the Loads and Resources Subcommittee indicates that the purchased power market in the southwest will be insufficient after the year 2009. Also, the current
WECC Power Supply Study indicates that resources in the next few years will not be able to overcome the projected load growth for this region. (Id. at 18.)

83. Mr. Davis stated that he is recommending that the Commission authorize NPC to spend their portion of the $300 million for EEC, albeit with a modified expenditure schedule and limitations on expenditures, for the following reasons:

   a) NPC needs additional base load capacity by 2012;
   
   b) 220 MW of coal base load capacity has been removed from NPC's system as a result of the earlier than expected retirement of the Mohave Station;
   
   c) Reid Gardner units 1, 2, and 3 are expected to be retired in 2012 and this will reduce NPC's base load coal capacity by 300 MW;
   
   d) Compared to a highly efficient combined cycle plant installed at the Harry Allen site, the EEC is a lower cost option on a 30-year PWRR basis for the base load case, and has a significantly lower PWRR for both the 20 and 30-year PWRR for the high fuel case;
   
   e) The EEC offers more capacity, 1200 MW, than the alternate plan with combined cycles, 1100 MW;
   
   f) Nevada ratepayers need a long-term hedge on the volatile natural gas market and a base load coal resource will provide this hedge;
   
   g) The EEC will provide the anchor resource that can justify the Intertie linking NPC’s and SPPC’s systems. (Id. at 18-19.)

84. Mr. Davis explained that a coal resource is an effective hedge against the volatile gas market for the following reasons:

   a) The long-term price volatility for gas is 2.5 times that of coal; and

   b) Other factors may cause long-term natural gas prices to be higher than projected, such as a declining supply of gas for the various basins in North America and possible over-reliance on the materialization of many gas supply and gas resource options that may or may not come to fruition. These options include the development of the LNG industry and the Artic natural gas transmission projects. (Id. at 20-22.)
85. Mr. Davis stated that the EEC is not the lowest cost resource option for SPPC. New coal units at Valmy or economy energy purchases are lower cost options for SPPC than the EEC. He is not recommending an expansion plan that relies upon economy energy (short-term purchases) because in low hydroelectric years economy energy from the Northwest is limited. The 2006 WECC Power Supply Study from its Loads and Resource Subcommittee indicates that the purchased power market in the Northwest will be deficient after the year 2010. For these reasons, he stated that he does not believe that reliance on short-term energy markets would be prudent for SPPC. (Id. at 23.)

86. Mr. Davis stated that SPPC should continue to pursue additional capacity at Valmy in lieu of the EEC. In Docket 04-7004, the Commission authorized SPPC to spend $3 million for preliminary development work for a new coal unit at Valmy, and he believes this is a minimal expenditure which will ensure that SPPC’s ratepayers have an owner-built coal option, if the EEC turns out not to be a viable project. (Id. at 24.)

87. Mr. Davis recommended the SPPC spend their portion of the $300 million for development activities for the EEC for the following reasons:
   a) SPPC needs additional base load capacity by 2012;
   b) The EEC is the lowest cost option compared to all other options other than a new coal addition at Valmy and economy energy;
   c) SPPC needs a long-term hedge on the volatile natural gas market and a base load coal resource will provide this hedge.
   d) The EEC will provide the anchor resource that will justify the Intertie linking NPC’s and SPPC’s systems. (Id. at 24.)

88. Mr. Davis stated that it is doubtful that the Companies could economically justify the Intertie between NPC and SPPC without the EEC. While this project would provide benefits to both Southern and Northern Nevada, the benefits of the intertie would likely not justify the $400 million investment that is required for the line. (Id. at 25.)

89. In response to clarification questions regarding provisions in contracts with equipment suppliers (e.g., boiler, turbine, etc.,) that allow the utility to cancel their contracts under certain
conditions and whether these provision are typical of the such contracts, Mr. Davis indicated that
these “off-ramp” provisions are typical. (Tr. at 659-660.)

90. In response to clarification questions regarding recent escalating purchased power prices
and whether Staff was supporting the EEC because of its concern over where wholesale market
prices were headed, Mr. Davis responded that purchased power prices reached the high prices this
summer even with gas in the $5 to $6 range. He opined that these high purchase power prices
suggest that there is currently a shortage of capacity. This indication is consistent with WECC
forecasts which predict a tight capacity market in the 2008-2009 timeframe. (Tr. at 671-672.)

91. Staff witness, Paul Maguire, Electrical Engineer, provided testimony addressing the cost
associated with the Intertie and the reasonableness of the preliminary 80/20 cost allocation between
NPC and SPPC, respectively, of expenses for development activities related to the EEC. (Exhibit
56 at 1.)

92. Mr. Maguire recommended that the Commission:

a) Approve $9.2 million to perform initial studies on the Intertie and noted that the
$9.2 million is included as part of the $300 million being requested for the EEC.

b) Approve the preliminary 80/20 cost allocation split between NPC and SPPC for
only the $300 million being requested for the EEC project in this filing. The Commission should
order the Companies to perform and provide a much more detailed cost-benefit analysis when it
makes the subsequent filing for approval to actually construct the EEC that adequately justifies a
final cost allocation between the Companies. The cost-benefit analysis should include the proper
modeling parameters to determine what benefit the Companies are receiving from the EEC project,
especially the transmission components such as the Intertie. (Id. at 2.)

93. With regard to the development activities related to the Intertie, Mr. Maguire stated that
the Companies are only requesting approval to spend $9.2 million to perform initial studies. (Id. at
2, Attachment PRM-2). It does not appear that the proposed Intertie would dramatically affect
either NPC’s or SPPC’s single largest contingency or hinder reliability. NPC’s single largest
contingency is currently the Silverhawk facility at 551 MW and, with the addition of the Intertie and
the first two 750 MW units of the EEC, that NPC’s single largest contingency will increase slightly
to 600 MW. NPC is expected to have to employ a transfer tripping scheme to take one of the 750 MW units off line in the event of a trip of the Intertie. (Id. at 3-4, Attachment PRM-5)

94. Mr. Maguire stated that he has concerns regarding the 80/20 cost allocation proposed by the Companies. The Companies appear to have based the cost allocation simply upon capacity allocation. Although that may be one way to allocate the costs associated with the coal plan itself, the EEC project includes over $500 million in transmission related expenditures that provide a widely varying benefit to each utility and have nothing to do with the coal plant capacity. (Id. at 5.)

95. Mr. Maguire stated that the cost allocation of the EEC should be developed subject to certain limitations and be based upon the benefits received from the project by each company. As far as the cost allocation for the coal generation capacity, each company should pay, at a minimum, a cost that is no greater than each individual company’s alternative self-build option. NPC does not have a viable self-build option but SPPC does (a third unit at the existing Valmy Station). An additional 300 MW of coal capacity at Valmy would cost SPPC approximately $554 million based on information provided in the Thirteenth Amendment. Based on the 80/20 cost allocation proposed by the Companies, SPPC’s share of the costs for the EEC will be $740 million or $186 million more compared to its alternative option, a third unit at Valmy. (Id. at 6, Technical Appendix 2 of 2, page 438.)

96. Mr. Maguire noted a number of concerns with the PWRR analysis that compared the EEC option with a third unit at Valmy. These concerns included, among others, the manner in which the Companies modeled losses, transmission charges and/or wheeling rates, the design of the third Valmy unit, and the in-service date of the Valmy unit. (Id. at 8-10.) Mr. Maguire is not implying that SPPC would be better off constructing its own coal unit at Valmy instead of participating in the EEC. He is indicating that to determine how much of the final cost of the EEC and the Intertie should be allocated to SPPC, the Companies must perform a much more thorough analysis. (Id. at 13-14.) Mr. Maguire stated that it appears that SPPC would receive little or no benefit from the Intertie but would be picking up 20% of the cost. He supported his position by providing a table that reflected SPPC’s capacity over the 20 year planning period. During the 20 year planning period SPPC is likely not to import very much power over the Intertie. (Id. at 11-12.)
97. Mr. Maguire stated that based upon his review of the analyses that were performed and filed, he believes the question of cost allocation comes down to how much of the costs associated with the Intertie and other associated EEC transmission infrastructure gets allocated to SPPC. (Id. at 12.)

98. Mr. Maguire stated that despite his concerns about the analyses performed by the Companies, he believes that the 80/20 cost allocation is reasonable for the $300 million being requested by the Companies to study the EEC in this filing. (Id. at 13.)

99. Staff witness, Ron Knecht, Economist in the Resource and Market Analysis Division, provided Staff's analysis and recommendations on the ability of the Companies to finance the plans included in their proposed IRPs/Amendment including their Preferred Plan and their Alternate Plan. (Exhibit 55 at 1.)

100. Mr. Knecht recommended that the Commission find that the Companies can reasonably finance their Preferred and Alternative Plans, included in their Applications without incentive ratemaking treatment. (Id. at 2.)

101. Staff witness, Yasuji Otsuka, Senior Economist, provided Staff's recommendations regarding the Companies' selection of the Preferred Plan as well as an analysis of the costs and economic benefits or impacts associated with the Companies' choice. (Exhibit 98 at 1.)

102. Dr. Otsuka recommended that the Commission find that:

a) While the Companies failed to provide some required information, overall they followed the procedure prescribed by regulation in the selection of supply expansion plans;

b) The estimates of the environmental costs and economic benefits or impacts included in the NERA Study are acceptable, albeit these estimates are subject to model limitations, such as simplifying assumptions and significant uncertainty regarding future events; and

c) The estimates of the societal costs and economic benefits to the State of Nevada do not conflict with the Companies' choice of the Preferred Plan. (Id. at 1-2.)

103. With regard to Dr. Otsuka's recommendation regarding societal costs and economic benefits to the State of Nevada, he provided Table 2, which follows, and noted that the Companies'
Preferred Plan did not provide the lowest projected environmental or societal cost. The Companies' Alternate Plan had lowest costs in both these categories. (Id. at 23-24.)

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He explained that the difference in cost between the two plans does not appear to be significant considering how the cost estimates were developed. A small change in the simplifying assumptions and/or an occurrence of future events that were not anticipated by the NERA Study is likely to change these estimates significantly. (Id. at 27.)

104. Dr. Otsuka stated that the NERA Study does not support one plan over the others in a conclusive manner, and consequently, sole reliance on the estimates in the Study should be avoided. He recommended that the projected cost and economic benefit estimates should be evaluated along with other objectives that the Commission considers important in selecting a preferred supply plan. Such objectives in this selection process may include system reliability, fuel diversity, increased use of renewable resources, and reduced exposure to volatile wholesale markets. (Id. at 28.)

SNWA Position

105. SNWA witness, Dennis Peseau, President of Utility Resources, Inc., provided testimony expressing SNWA’s general but cautionary support for NPC’s IRP. (Exhibit 43 at 1-2.) SNWA generally endorses moving forward with the planning and permitting of the EEC, and related transmission facilities, including the Intertie. The reason that SNWA’s endorsement is
cautionary is due to the extreme uncertainty with respect to any actual building of Phase One of the EEC, and the interdependence of the associated transmission, the Intertie, and even the Clark CTs. (Id. at 6.) Quite some time has elapsed since the completion of major coal facilities in the western U.S, and currently there exist both strong proponents and opponents of major new coal generating facilities. Even though the EEC will use the latest clean-coal technology, the siting, water, transmission construction, permitting, and public endorsement of the facility will certainly pose a significant challenge. For these reasons, SNWA urges the Commission to grant only preliminary approval, but require extraordinary updating and progress reports with appropriate off-ramps should the project become mired in difficulties. (Id. at 7.)

106. Mr. Peseau stated that he supports NPC’s request for approval of up to $300 million through 2008 for development activities related to the EEC and Intertie, qualified by its successful receipt of an air permit for the EEC. (Id. at 7.)

107. In response to questions from Commissioners regarding the capacity situation in the West, Mr. Peseau responded that he believed that there is currently adequate capacity but that the power users in the West would be squeezing reserve margins in the next few years. With respect to the resource situation by the end of the decade, it is time to decide what type of capacity to build and then build it. (Tr. at 509-511.)

**BCP Position**

108. BCP witness, Kevin Woodruff, Principal of the consulting firm of Woodruff Expert Services, provided testimony related to the Companies’ proposal to proceed with Phase One of the proposed EEC. (Exhibit 48 at 1-2.)

109. Mr. Woodruff stated that the his major conclusions regarding the Companies’ proposed request for approval of the EEC as follow:

a) The Companies have not shown that construction of the EEC and its related transmission will meet their customers’ interests in a reasonably-priced and physically reliable way. (Id. at 2.) The Companies specifically: i) have not demonstrated that their plan provides the lowest cost and largest improvement in system reliability over the greatest range of potential scenarios; ii) have not demonstrated that the EEC is required in order for NPC to comply with the RPS; iii) have
only partially supported their position that their preferred plan reflects a large increase in fuel
diversity; iv) have not supported their statement that the Intertie will potentially allow a joint
dispatch of the two systems for the first time resulting in significant savings and reliability
improvements, and the Companies did not even complete an economic analysis that would support
their claim; and v) have only analyzed a very limited set of options in developing their resource
plans; and vi) until the Companies conduct RFPs, the Commission cannot have any confidence that
the Companies have identified the best means for meeting their customers’ loads (Id. at 4-10.); and

b) The Companies’ analysis of Phase I of the EEC ignored several critical risks that
the EEC poses to their customers and did not include a reasonable assessment of the availability and
cost-effectiveness of alternatives to the EEC. (Id. at 2.) NPC has not adequately addressed the risk:
i) that the 1200 MW of capacity from the EEC appears to be a poor fit for its long-term resource
needs; ii) that the EEC and Intertie may raise NPC’s planning and operating reserve requirements
thus raising NPC’s operating costs, and NPC cannot yet say that it has implemented a plan that will
guarantee that an outage of the Intertie will cause only a 600 MW contingency for NPC; iii) that the
financing necessary to build the EEC may not be achievable; iv) that the EEC imposes significant
additional carbon regulation risks on the Companies’ customers. This “carbon regulation risk”
should be a key concern of this Commission in reviewing the Companies’ resource plans and of
their proposal to build the EEC. (Id. at 13-30.)

110. Mr. Woodruff stated that based upon his conclusions he recommended that the
Commission should take the following steps regarding the Companies’ request related to their
proposed EEC project:

a) Authorize NPC and SPPC to continue development and permitting efforts for the
EEC and related transmission projects. He clarified that such authorization should only continue
through November 2007 and should not allow the Companies to make any major equipment orders.
A total amount of $28.2 million should be authorized to fund development and permitting efforts
through November 2007. (Id. at 2.) Limits on the Companies’ EEC development expenses are
necessary to limit customers’ exposure to the risks that the Companies will not be successful in
developing the EEC. He reduced the Companies’ proposed budget of $300 million to include only
those expenses needed to continue the development and permitting of the EEC, and excluded in particular any authority to place major equipment orders (Id. at 37.); 

b) Direct the Companies to issue RFPs for resources to meet their respective long-term energy and capacity needs before they seek authorization of any further funding for EEC development. The Companies should determine which resources from those submitted in response to the RFPs and those being self-developed will best meet the needs of their customers over the long-term (Id. at 2.); and 

c) Direct the Companies to re-file revised resource plans in July 2007 to reflect the results of these RFPs and the Companies’ further efforts to develop their own resources. (Id. at 2-3.) The Companies cannot possibly know all the reasonable alternatives for meeting their loads reliably and at least-cost unless they solicit the market for proposals. Also, at least in the western states, the use of RFPs to meet long-term needs is much more the industry standard than the assumption that utilities should plan and build all resources as the Companies have. (Id. at 40.)

111. Mr. Woodruff stated that the completion of the EEC on the proposed schedule and budget is highly uncertain and that if the Companies cannot succeed in obtaining all the necessary permits and fuel supplies, they may be unable to complete the project in a timely manner, leaving the Companies’ customers exposed to the volatile spot markets and poor physical reliability. He believes that the Companies can succeed at resolving these issues if given enough time and money. The possibility for delays in the development schedule is significant, as is the possibility that project costs will rise as permitting and coal transport issues are resolved. Committing to the EEC at this time thus poses substantial reliability and cost risks to the Companies’ customers. (Id. at 31-32.)

112. Mr. Woodruff also stated that the Companies’ proposal to meet a substantial portion of their open position with a single 1500 MW resource exposes the Companies’ customers to a major single source risk. If the Companies fail at completing the EEC, their customers will be that much more exposed to volatile energy prices and disruptions in reliable service. (Id. at 34.)

113. With regard to the recommended 2007 re-filed resource plan filing by the Companies, Mr. Woodruff stated that the filing should include:
a) The relative "fits" of coal, gas, and other technologies with NPC's and SPPC's projected loads shapes and resource portfolios;

b) The impact of the Intertie and possible development of LS's Southwest Intertie Project, on NPC's planning and operating reserves;

c) Financial plans that support the utilities' achievement of their preferred plans, plus alternative financial plans based on alternative resource plans, including - for a point of reference - continued reliance on short-term markets;

d) Carbon regulation risk, its potential impacts on Nevada ratepayers, and its implications for resource planning;

e) A more detailed summary of the status of the various permitting and development and coal supply and transportation contracting efforts and an assessment of the risks these issues pose to timely and cost-effective completion of the project;

f) An analysis of the reasonableness of the Companies' development schedule for the EEC as compared to industry development schedules for projects of similar size, and the risks posed to customers by the relatively large development expenses being proposed in the early years of the schedule; and

g) Means for mitigating the "single source" risk that such a large project poses for Nevada customers, consistent with NAC 704.937 (5). (Id. at 45-46.)

NCARE Position

114. NCARE witness, Ronald Lehr, Consultant, provided testimony addressing the potential for an expanded role for renewable energy and energy efficiency and the need for additional attention to environmental impacts of the generation resource included in NPC's resource plan. (Exhibit 97 at 2-3.)

115. Mr. Lehr stated that NCARE recommended the following:

a) The Commission should not approve NPC's Resource Plan as it is inadequate and has not considered a full range of options. Also, the plan does not make sufficient use of renewable and energy efficiency resources, and it does not achieve a sufficient reduction in the environmental impacts of power generation. (Id. at 12-13.)
b) The Commission should direct NPC to prepare an alternative plan based on higher levels of renewable energy and energy efficiency that could, at a minimum, obviate the need for EEC Unit One. (Id. at 13.)

c) The Commission should defer any decision about EEC Unit 2, given: 1) the uncertainties about future economic conditions; 2) the potential for using renewable energy, energy efficiency, CHPC and IGCC technology with carbon capture and sequestration; and 3) the fact that new information on the cost, performance, and availability of these resources will continue to become available. (Id. at 45.)

116. Mr. Lehr indicated that NCARE has reviewed renewable resources available in Nevada and finds them abundant and geographically and technologically diverse. NCARE has analyzed the potential for greater use of renewable energy and efficiency and the costs of an illustrative mix of renewable resources and DSM that could be sufficient to replace the first coal unit of the EEC project. (Id. at 14.)

117. Mr. Lehr presented NCARE’s plan, the “Balanced Plan,” of renewable resources and DSM which he stated is an “illustrative plan” which he believes could replace the first coal unit of the EEC. (Id. at 14.) NPC should not commit to the second coal unit of the EEC project and it would be imprudent for NPC to make a commitment to the second coal unit before carefully evaluating other resource options. (Id. at 22.)

118. Mr. Lehr stated that NCARE is not proposing that its Balanced Plan portfolio be substituted by the Commission for NPC’s plan. NCARE offers its plan as an illustration of how an alternative plan can save money, lower risks, and protect the environment relative to NPC’s plan. (Id. at 20.)

119. Mr. Lehr stated that the Commission should be concerned about global warming as it reviews NPC’s proposed plan. Regulation to curtail emissions of greenhouse gasses (GHGs), the most abundant of which is CO₂, is one of the greatest risks that NPC and its customers face. He believes that it is virtually inevitable that financial penalties will be imposed on emissions of CO₂ by utilities within the lifetime of the new coal power plants proposed by NPC, and this is likely within the next decade. Any utility that does not plan for and hedge this risk threatens the financial
stability of both its customers and its shareholders. Mr. Lehr supported his position by providing a summary of scientific evidence regarding the level of GHGs and information regarding current initiatives (in the United States and around the world) to curtail GHGs. (Id. at 32-36.) He conceded that NPC attempted to estimate the cost of GHG reduction policies on its plan but believes that NPC’s estimate of the cost per metric ton of GHG is at the very low end of the range of possible CO2 costs. Even using the low CO2 costs that NPC used, ratepayers would pay an extra $415 million for each unit of the EEC over the first thirty years of each unit’s life. (Id. at 37.)

**NRA Position**

120. NRA witness, William Monsen, Principal with MRW & Associates, Inc., provided testimony addressing the Companies’ proposal to develop the EEC project and associated transmission facilities and to have the Commission authorize up to $300 million in costs associated with these development efforts. He indicated that in his testimony he would:

a) Identify possible alternatives to the EEC that could provide greater ratepayer benefits;

b) Identify and develop estimates of the magnitude of the benefits associated with bringing similarly-situated projects online before the expected online date for the EEC project;

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1 After LS was granted intervention for Phase III, which included the transmission issues, LS did not appear at hearing. More troubling is the evidence received at hearing regarding how LS retained Mr. Monsen to be its witness on the EEC issues. It became clear that Mr. Monsen had been retained by LS with respect to the Phase II issues after LS’ intervention on the EEC had been denied. Furthermore, Mr. Monsen informed the Commission that LS had retained him with the apparent intent of inserting its position into the Commission’s hearing record through another party. (Tr. at 587.) LS contacted Mr. Monsen on September 1, 2006, and asked if he was available to testify in the IRP proceeding. (Exhibit 47 at 20-21.) LS indicated to Mr. Monsen that it was not a party to the IRP proceedings, but if it didn’t become one, possibly “other entities that were intervenors that would have similar interests ... might sponsor my testimony.” (Tr. at 587.) A third draft of testimony was sent to LS Power on September 13, 2006. (Exhibit 47 at 43.) Mr. Monsen ceased to work for LS Power on September 13, 2006. (Id. at 32.) Hours prior to the testimony filing deadline, Mr. Monsen was shifted to another party. (Exhibit 47; Tr. at 531-546, 587-589, cross-examination of Mr. Monsen.)

LS chose not to answer the question of how Mr. Monsen was shifted to another party. Consequently, the Commission is left with the record evidence provided by Mr. Monsen. This reflects that several hours prior to the pre-filed testimony deadline, Mr. Monsen was under the employ of another party yet LS was still commenting on the content of his pre-filed testimony.

Actions taken to get the LS witness before the Commission, one way or another, appear to abuse the Commission’s process. As such, this apparent attempt to thwart the Orders of the Commission and the Eighth Judicial District Court must be viewed as a subterfuge and is highly inappropriate. The Commission recognizes a legitimate party’s right to offer any witness it believes represents its interests. The Commission also appreciates Mr. Monsen’s candor and contribution to the hearing record. Nonetheless, the evidence clearly shows LS’ apparent attempt to mislead the Commission. In light of the fact that LS must still obtain regulatory approvals from the Commission and other Nevada regulatory agencies in order to advance its financial interests, the Commission is puzzled by these maneuvers.
c) Discuss the lack of market data supporting the Companies’ claims that the EEC is the least-cost resource option for providing fuel diversity and other benefits to ratepayers; and

d) Propose that the Commission authorize limited development funding for the EEC. (Exhibit 44 at 1-2.)

121. Mr. Monsen provided the following recommendations to the Commission:

a) Authorize the Companies to continue development efforts of the EEC on a closely-monitored basis with development milestones and cost caps on capital expenditures to ensure that ratepayers are not placed at risk for excessive development costs. If the EEC is found to be deferrable by other generators, the Companies’ shareholders should bear a portion of these development costs;

b) Not authorize the Companies to acquire major components for the EEC before the Companies obtain all critical path permits for the EEC. If the Companies feel that acquiring these major components is prudent, they should be prepared to demonstrate the reasonableness of those actions to the Commission; and

c) Require the Companies to solicit the best and final bids from all interested parties in order to demonstrate the reasonableness of the Companies’ Preferred Plan. An Independent Evaluator, selected by the Commission, should evaluate all proposals and provide its recommendations regarding the least-cost resource plan to the Companies and the Commission. (Id. at 29.)

122. Mr. Monsen stated that two coal generation plant alternatives to the EEC exist and, if pursued, could provide greater benefits to ratepayers than the EEC. These projects include the Sithe and LS projects. Both of these projects appear to be further along in their efforts to obtain their required permits and both could provide benefits to the Companies’ ratepayers that are similar to those provided by the proposed EEC project assuming the same on-line date. (Id. at 11.) The power supply from an independent generator is as secure as the supply from a utility self-build project and typical contracts with IPPs include strong incentives to ensure that IPP projects come on-line, on time, and maintain high unit availability. (Id. at 12.)
123. Mr. Monsen stated that a delay in the online dates for EEC Units 1 and 2 will result in a significant increase in ratepayer costs. He estimated that, in the case of NPC, retail rates would increase by approximately one cent per kWh as a result of such a delay. Because similarly-situated coal-fired power projects are further developed than the EEC, they might be online before the expected online date for EEC and that this would allow ratepayers to experience benefits related to rate, fuel diversity, Intertie, and other benefits at an earlier date. He conservatively estimated that an on-line date that is one year earlier than the EEC would save ratepayers about $90 million per each 750 MW unit per year. (Id. at 17-22.)

124. Mr. Monsen stated that long-term purchase power agreements ("PPAs") for similarly situated coal-fired power plants provide benefits to ratepayers. A properly structured long-term PPA creates a contractual obligation for the project to be on-line, and to provide its output for the benefit of the utilities’ customers or compensate them financially for failing to deliver under the contracts. With a PPA, an IPP’s project becomes, in effect, a firm resource for the Companies. (Id. at 23-24.)

125. Mr. Monsen stated that the Commission cannot judge the reasonableness of the EEC given the evidence provided by the Companies. The Companies have not provided the Commission with evidence that the EEC is the least-cost resource available for providing benefits like those provided by the EEC. He believes that the Companies should demonstrate to the Commission that their Preferred Plan is truly the least-cost means to obtain the risk mitigation benefits attributed to it. (Id. at 26.)

126. Mr. Monsen stated that the Companies should solicit binding expressions of interest from project developers and compare the benefits and costs associated with those proposals to its own resources and noted that such a “market test” would provide a check on the reasonableness of the Companies’ plan. The Companies should solicit bids from project developers for various types of resources using an RFP process and the bids received as a result of the RFP should be evaluated by an independent evaluator (selected by the Commission), who would compare the costs and benefits of the various resource options, including a self-build option, and then develop a short list of recommended resources with which to negotiate. (Id. at 27.)
127. Mr. Monsen stated that allowing the Companies to invest up to $300 million in the EEC is unreasonable given the information available to the Commission to justify such expenditures. Moreover, he noted that it is also not reasonable to allow the Companies to procure major components for the EEC. He warned that the Commission should be cautious with regards to the Companies’ proposal to spend up to $155 million prior to obtaining its air permit for Phase 1 of the EEC. (Id. at 28.)

128. In response to clarification questions regarding the timing and the ordering of the boilers and other equipment, Mr. Monsen stated that these items are long lead time items and that a delay in the ordering of this equipment could certainly affect the schedule of a coal-fired project. (Tr. at 557-558.)

129. In response to clarification questions regarding whether or not there is adequate capacity available to obviate the need for the EEC, Mr. Monsen responded that he is less optimistic than another witness, Dr. Peseau, who testified regarding the adequacy of resources in the West. He believes the western region is currently “tight” on resources and does not believe that relying on the wholesale market makes sense. (Tr. at 581-582.)

NPC and SPPC Rebuttal Position

130. Mr. Denis disagreed with Staff’s position that the Companies be precluded from making a filing requesting Commission approval to proceed with the construction of the EEC and Intertie subsequent to the air permit until numerous milestones, such as transmission line permits, water permits and a term sheet with the railroad, have been achieved. The Companies agreed that these are important milestones but he does not believe that the subsequent filing should be delayed pending completion of these items. To the extent that these milestones have not been achieved at the time of the next filing, the Companies will provide a complete and thorough progress report on the outstanding items with estimated completion dates. (Exhibit 67 at 2-3.)

131. Mr. Denis stated that after the Companies have obtained their air permit, they should provide the following information in their subsequent filing in which they ask for Commission approval for construction of the EEC and Intertie:
a) A request for Commission approval to proceed through construction of the EEC and Intertie based on detailed engineering, construction and cost estimates, and a refined project schedule;

b) A detailed analysis to support the allocation of costs for EEC and the Intertie between SPPC and NPC;

c) An update of the environmental cost and economic benefits;

d) An update of fuel costs, including rail transportation costs;

e) An update on coal sources;

f) An update on carbon dioxide emission regulations;

g) An update on the impact of the EEC and the Intertie on the Companies’ planning and operating reserves, if any;

h) An update of the financial plan;

i) An update of the transmission line permits;

j) An update of the water permits; and

k) An update of the site selection. (Id. at 6-7.)

132. Mr. Denis disagreed with Mr. Woodruff that the EEC does not offer any unique reliability benefits that most other types of generation could not also provide. The proposed EEC will be a utility-developed project subject to Commission oversight; completion of the project will avoid the risks of relying upon market purchases or contractual arrangement for long term supplies; and the transmission component of the project, the Intertie, will assist the Companies in fulfilling their RPS requirements thereby enhancing fuel diversification efforts and reliability of supply. (Id. at 10.)

133. Mr. Denis disagreed with Mr. Woodruff’s position that completion of the EEC and the Intertie on time and on budget is highly unlikely. The Companies have proposed a realistic and achievable schedule based on the best information available at this time. The Companies oppose many of the proposals advocated by Intervenors, which would virtually guarantee that neither the schedule nor the budget could be met. The Commission should reject proposals from the Parties that affect the schedule or budget. (Id. at 12.)
134. Mr. Denis stated that the Companies disagree with the BCP and NRA regarding their recommendations that the Commission order the Companies to issue an RFP to identify qualified alternatives to the EEC and that long-term purchased power agreements offer advantages over utility-owned generation. The BCP and NRA proposals would only delay the EEC and the Intertie and increase consumer costs. The Companies support evaluation of resource options to meet their needs and spent considerable time and effort evaluating the same resources that are now proposed as alternatives to the EEC before deciding to proceed with the EEC. He noted that the Companies utilize the RFP process on a regular basis to fill their short-term needs. (Id. at 13.)

135. Mr. Denis stated that an RFP process would likely not identify projects, other than those that have already been examined by the Companies that are capable of replacing the EEC. The Companies have already spent a year exhaustively exploring the merits of both the Sithe and LS projects, conducting what the Companies would consider during an RFP to be a due diligence investigation. The Companies already know what these projects are capable of offering, are familiar with the counterparties, their financial capabilities, their technical expertise, their project plans, and the types of commitments they are willing to make. He summarized that given the work the Companies have already done to assess the Sithe and LS projects, an RFP is simply unnecessary and that an order requiring the utilities to proceed with an RFP would virtually guarantee that the EEC will not be online as currently scheduled. (Id. at 14-15.)

136. Mr. Denis estimated that a straightforward RFP process would take at least 18 months to complete. He also stated that he did not see any merit in the BCP’s and NRA’s proposal that the Commission appoint an independent evaluator to oversee the RFP process because this would substitute the judgment of a so-called independent third party for that of the Companies and the Commission which is fully qualified to evaluate resource options that are brought before it. (Id. at 17.)

137. Mr. Denis strongly disagreed with Mr. Woodruff’s suggestion that an all source RFP with an independent evaluator could be completed by July 2007. He asserted that the earliest that the subsequent filing could be expected to be made is May 2008. (Id. at 18.)
138. Mr. Denis stated that customers are clearly not better off when utilities buy power in the wholesale market from IPPs rather than building new generation to meet load. Consistent with Nevada’s energy policy, the Companies’ proposals are intended to reduce reliance on the volatile wholesale market by increasing utility-owned generation. In addition, Mr. Denis stated that power purchase agreements present unique risks for customers. While contractual obligations serve to insulate customers from price, unit performance, and equipment failure risk, they are no substitute for the protections that are afforded to customers through regulatory oversight of utility-owned assets. With a power purchase agreement, the remedy for non-performance is litigation not generation. (Id. at 18-20.)

139. Mr. Denis stated that he disagrees with Mr. Davis’ recommendation that the Companies should also continue to pursue other alternatives other than a self-build option because self-build options are superior to PPAs for large, strategically important projects like the EEC. Further discussions with LS and Sithe would distract the Companies from proceeding with the EEC, cause delay and increase costs, all to the detriment of customers. (Id. at 22-23.)

140. Mr. Pottey disagreed with Mr. Woodruff’s contention that NPC can comply with the RPS without the Intertie. Because NPC’s system is so much larger than SPPC’s system, by 2015 two-thirds of SPPC’s entire load would be served by non-dispatchable, must take, and, in some cases, intermittent energy. This energy would likely exceed SPPC’s total load in some hours and make it nearly impossible to reliably and economically operate SPPC’s system. (Exhibit 65 at 7.)

141. Mr. Pottey joined Mr. Denis in disagreeing with Mr. Woodruff that NPC should issue an RFP for the required long-term resources. There is not a surplus of coal-fired generation capacity in the region and anyone responding to an RFP for additional coal-fired generation would need to construct a new power plant. The Companies spent nearly a year in extensive negotiations with the only two IPPs proposing to build coal fired generation within the Companies’ system in time to meet a 2011 and 2013 time frame. (Id. at 9.)

142. Mr. Pottey stated that long-term PPAs do not offer the same reliability and certainty as Company-owned facilities. He explained that experience has shown that when performance under a long-term contract is uneconomical, suppliers often fail to deliver according to the original
terms and conditions of their long-term contracts. Regulated utilities operate under an obligation to serve and are not similarly motivated. (Id. at 10.)

143. Mr. Pottey disagreed with Woodruff that the EEC is a poor fit for NPC's long-term resource needs. With the addition of the EEC, that baseload capacity exceeds the load by less than 200 MW in all but 3.5% of the hours. Further, with forecasted load growth, in a few years there would be very few hours when the baseload capacity exceeds the load. (Id. at 10.)

144. Mr. Pottey disagreed with Mr. Woodruff that gas resources such as combined cycles and CTs appear to be a more appropriate resource choice for NPC. There is certainly a place for gas-fired combined cycles and CTs but NPC has a need for fuel diversification and additional base-load coal fired capacity. (Id. at 11.)

145. Mr. Pottey disagreed with Mr. Woodruff that the Intertie might become a new largest single contingency. The Companies have considered this issue and determined that there is an acceptable level of risk associated with dealing with outage of the Intertie. The Companies will provide an update on the EEC's impact on planning and operating reserves when they file for project approval following receipt of the air permit in 2008. (Id. at 15.)

146. Mr. Pottey did not believe that NCARE's proposed "Balanced Plan" is feasible and, given the amount of new renewable resources that would have to be added, it also lacks credibility. NCARE's proposal doesn't adequately account for: a) Nevada's experience with contract failures; b) geothermal and wind resource uncertainties that need to be overcome; and c) uncertainty regarding future wind and geothermal costs. (Id. at 16-19.)

147. Mr. Pottey disagreed with Mr. Woodruff that it is not clear that coal projects will offer the same fuel diversity benefits compared to gas that they have in recent years. While it is logical that there is some correlation between fossil fuel commodities, he is not aware of any market expectation that the future price spread between gas and coal will translate into gas-fired generation displacing coal on a long-term basis. One of the most foundational strategies in resource planning is to reduce reliance on a single fuel type and noted his agreement with Staff's position that coal is an effective hedge against the volatile natural gas market. (Id. at 27.)
148. Mr. Rogers disagreed with Mr. Woodruff's position that financing the necessary capital to build the EEC may not be achievable. The Companies can finance their Preferred Plans but he indicated that the high capital expenditures of the Preferred Plans will require external, permanent capital, as well as working capital flexibility. Raising this capital will apply near term pressure on the Companies' credit metrics and require a continued constructive regulatory environment. (Exhibit 71 at 2-3.)

149. Dr. Harrison clarified that his estimates of environmental costs related to future CO₂ emissions do not provide the estimates of the added costs to customers of potential future carbon regulatory programs under each of the Resource Plans. In the case of CO₂ emissions under a cap-and-trade program, these costs represent estimates of the added future resource costs to control emissions, assuming that the future potential allowance price provides an estimate of the cost per ton of reducing emissions at the margin in any future year. These future costs do not reflect the specific alternatives that NPC/SPPC would have to reduce their emissions in response to a cap-and-trade program. (Exhibit 100 at 4.)

150. Dr. Harrison explained that there are two factors that would affect the potential future costs to customers if a cap-and-trade program for CO₂ were in place. These factors include:

a) The opportunities the Companies would have to reduce the CO₂ emissions when and if a cap-and-trade program were put in place; and

b) The initial allocation of allowances the Companies would receive under such a cap-and-trade program. In summary, he noted that the environmental costs do not measure the likely cost to consumers in Nevada. (Id. at 5.)

151. Dr. Harrison provided Figure 1 to place the CO₂ allowance price projections included in Table II-3 of Mr. Woodruff's testimony into perspective. Figure 1 is different than the projections included in Mr. Woodruff's testimony in that it includes only projections for cap-and-trade proposals that have been formally introduced, reflect the timing of the various proposals, are in the same "year dollars," and are all based on units of carbon dioxide. The data in Figure 1 suggest that more recent proposals are associated with lower predicted 2020 CO₂ allowance prices. Also, the latest proposal, the Udall-Petri proposal is similar to and slightly lower than the predicted
safety valve price under the National Commission on Energy Policy ("NCEP") proposal. He also reiterated that there is uncertainty regarding whether CO₂ cap-and-trade legislation will be passed, when it might be passed, what specific provision it might contain, and what future allowance prices might be approved. (Id. at 10-12.)

152. Dr. Harrison stated that Mr. Lehr’s assertion that $6.70 per metric ton is at the very low end of the range of possible carbon dioxide costs was not supported by Mr. Lehr and that recent U.S. Congressional proposals have produced values in this range. (Id. at 16.)

153. Dr. Harrison also stated that Mr. Lehr’s financial risk to ratepayer calculations associated with CO₂ costs ignores the opportunities that NPC may have to reduce its carbon emissions at a lower cost than the price of allowances and does not consider the initial allocation of allowances that NPC would likely receive under a cap-and-trade program. (Id. at 17.)

154. David Sims agreed with Mr. Woodruff that a delay of the EEC is harmful to customers. However, he stated that Mr. Woodruff’s approach is much more likely to leave customers exposed to volatile spot market and poor physical reliability. Mr. Woodruff has proposed a process that virtually guarantees that the project will not be completed on schedule and that customers will be exposed to market volatility and reliability risks. The risk of delay can be adequately addressed if the Commission authorizes the expenditures set forth in the Action Plan. (Exhibit 57 at 2-3.)

155. Mr. Sims disagreed with Mr. Woodruff’s argument that the Companies are developing the EEC on an accelerated schedule and that by pursuing a heavily front-end loaded schedule the Companies are putting its customers at risk. The Companies have developed a schedule and adopted a construction approach based upon the best available information in order to support the proposed in-service date and minimize costs. This includes committing to certain critical path items, such as the fabrication of the boiler and major equipment. The risk to the Companies’ customers is limited by the specific dollar authorization the Companies are requesting in this proceeding, and the subsequent filing they will make in 2008. (Id. at 4-5.)

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2 The NCEP CO₂ emission price proposal is the price proposal that Dr. Harrison used in his analysis. (Exhibit 1, NERA Report, Technical Appendix II: Tr. at 1208, 1209.)
156. Mr. Sims disagreed with Mr. Woodruff's recommendation that the Commission place limits on the Companies' development costs for the EEC and require them to return when the "proposed development schedule is in fact prudent." The Companies' proposed schedule is reasonable and the Companies expect to save customers between $200 million and $300 million for every year that the EEC is in service. Given the high interest from other utilities in North America and the rest of the world in building similar coal-fired facilities, the Companies must order the first boiler and secure fabrication space or face being locked out of the market for an indefinite period of time. If some fatal flaw appears in the Ely site after the Companies have ordered the boiler but prior to final permit issuances, alternatives are available to minimize costs and the Companies would work in close consultation with Staff to pursue these alternatives. (Id. at 6.)

157. Mr. Sims addressed Mr. Davis' recommendations that the Companies obtain the permits for the construction of the transmission lines or have reasonable assurance that they will be obtained before they file their amendment requesting final approval of the EEC. The draft Environmental Impact Statement should be issued in the Fall of 2007 and this should provide the necessary assurance that the permits will be obtained. It is not necessary to delay the filing until these permits are received. (Id. at 8.)

158. Mr. Sims also disagreed with Mr. Davis' proposed expenditure schedule for EEC development activities. The effect of Mr. Davis' recommendations will be to put the in-service date at risk and increase the final cost of the project. (Id. at 9-11.)

159. Mr. Brignola responded to claims made by Mr. Woodruff and Mr. Lehr regarding the uncertainty of future coal prices. The Companies hired the Boyd Company to prepare a forecast of the anticipated long-range coal price and transportation costs trends through 2026, and the Companies believe that the work provided by the Boyd Company is the best information available regarding future coal and transportation costs. (Exhibit 63 at 2-3.)

160. In response to Mr. Lehr's testimony that there may be coal supply disruptions due to railroad track problems, Mr. Brignola stated that disruptions due to track problems are possible, but that the Companies will establish and maintain target coal inventories that should allow them to weather these types of disruptions. (Id. at 3.)
161. With regard to Mr. Davis’ testimony that the Companies did not include in their estimated coal fuel costs their share of the costs for upgrading the Union Pacific railroad tracks to allow for 150 car trains, Mr. Brignola stated that this issue is subject to negotiation. Private capital contributions to the railroad’s infrastructure prior to the initiation of service have not been customary in the rail industry and were not included in the coal fuel cost estimate competed in March 2006. (Id. at 4.)

162. Mr. Brignola disagreed with Mr. Davis’ testimony that the Companies did not include in their estimated coal fuel cost the cost for leasing and maintaining rail cars for hauling coal to the site and the cost of hauling coal over the 100 mile spur from the Union Pacific tracks to the EEC. The estimated coal fuel costs provided by Boyd Company include the cost of cars that would typically be incurred by the shipper to deliver the coal to the EEC. (Id. at 5.)

163. Mr. Brignola responded to Mr. Davis’ recommendation that the Companies should provide the Commission with a term sheet with the railroad supplier prior to filing IRP amendments for authority to construct the EEC and Intertie. In recent years, the railroads have received numerous requests for rail service from developers of coal plants that ultimately ended up not going forward, and as a result the railroads are not willing to commit the substantial internal resources to respond to the request unless they view the request as viable. In the absence of a clear endorsement by the Commission of the EEC, the railroads likely will be reluctant to continue developing a term sheet on a priority basis and to engage in detailed negotiations. (Id. at 5.)

164. Mr. Brignola stated that the Companies intend to respond positively to Mr. Davis’ recommendations that the Companies hire a rail transportation consultant, and complete a coal inventory study and a final study on the coal source. (Id. at 6-7.)

Commission Discussion and Findings

Resource Planning Approval for Phase I of the EEC

165. The Commission has evaluated the resource plan options presented by the Companies from a number of perspectives. It has assessed the recommendations and analyses presented by the Parties and has carefully evaluated the record in this proceeding. The Commission has considered the infrastructure needs to support the State’s economy; resource adequacy in
Nevada and the WECC; fuel diversity; projected fuel costs and availability; economic benefits of facilities additions; impact on customers’ rates; projected environmental impacts and costs; the timing of new resources; available generation options; the level of capacity available from renewable energy resources; and conservation and load management.

166. The Companies, Staff, SNWA, and NRA all projected declining reserve margins and/or capacity shortages by the end of this decade. The Commission focused on: the Companies’ (in particular NPC’s) large and growing open position at a time of impending capacity shortages; the Companies’ (in particular NPC’s) aging fleet of coal plants; the Companies’ need to upgrade and modernize their resource portfolio by adding Company-owned or controlled baseload capacity; the diversification of the Companies’ resource mix to provide a hedge against natural gas price volatility; the cost consequences associated with a delay in the development of coal-fired generation, expected to be between $200 and $300 million per year; and the lack of regulatory control over IPP generation development.

167. The Commission has paid particular attention to expert projections of the resource situation in the Western United States over the next ten-year period and how this affects the options that the Companies will have. Specifically, the Commission recognizes the increased demand for natural gas-fired generation in the West. This demand is exacerbated by California’s recent actions addressing greenhouse gases and the possibility of changes in environmental regulations, which may impact the costs that Nevada customers pay for their power.

168. Acceptance of the Companies’ Preferred Plan per this order addresses the Commission’s concerns and is in the public interest. Therefore, the Commission is granting the Companies’ request to proceed with the development of Phase I of the EEC and accompanying transmission line as articulated in this Order.

$300 Million for EEC Development Activities; 80/20 Cost Allocation

169. The Companies have requested Commission approval of $300 million for development activities related to the EEC. They have stated that they will limit these expenditures to $155 million until they have obtained the final air permit. Staff, BCP, and NRA supported further expenditures related to the EEC but have requested that the Commission place limitations on
the requested expenditures. These limitations were directed at expenditures for major equipment orders and other expected expenditures that are scheduled to be made prior to the receipt of an air permit for the EEC. The Commission acknowledges that it has been the Commission’s practice to require permits be obtained and the UEPA process be completed before authorization is given to proceed with the procurement of major equipment for a utility facility. However, in this case the Commission is convinced by the Companies’ assertions that their proposed EEC development expenditures and schedule, which includes commitments for major equipment prior to the time that all permits have been obtained, puts them in the best position to place the EEC in-service on time and at a lower cost than do the expenditure schedules proposed by other parties. Therefore, the Commission approves the Companies’ request for resource planning approval of $300 million for development activities associated with the EEC with a limitation of $155 million placed on expenditures until the Companies have obtained their final air permit for the EEC. The Commission further orders the Companies to provide evidence to the Commission, Staff, and the BCP demonstrating that they have received the air permit before proceeding to spend expenditures beyond the $155 million.

170. With regard to procurement of major equipment for the EEC, the Commission cautions the Companies that they must act prudently when contracting with equipment manufacturers to protect their own interests and the interests of their customers should circumstances result in the cancellation or delay of the EEC Units 1 and 2.

171. The Commission is granting approval of the Companies’ request to initially allocate EEC Phase I development activities costs between NPC and SPPC using an 80/20 cost allocation, respectively. Based on the record, it is clear that the initial cost allocation was made for analytical purposes and that the Companies intend to submit a subsequent analysis once the costs and benefits to each company are more clearly defined. The Commission expects that the cost allocation may change once further analysis is completed. The Commission recommends that NPC and SPPC view their respective share of the EEC and/or Intertie as distinct projects and that the benefits received from each company’s share of these projects should be compared to other options that they have available. In the case of SPPC, further analysis may reflect that the benefits received from the EEC
or Intertie do not compare favorably to other available options or warrant ownership of one or both of these projects.

2008 Filing Requirements

172. Upon receipt of the air permit, the Companies will prepare and submit a subsequent filing in the form of a resource plan amendment ("EEC Amendment") in which they will ask for Commission approval to proceed with the construction of the EEC and Intertie based on detailed engineering, construction and cost estimates, and a refined project schedule. Several of the Parties in this proceeding recommended that the Commission order the Companies to include analyses and information in the filing that is in addition to what the Companies proposed. In rebuttal testimony, the Companies offered to include an additional list of items in the EEC Amendment. The Commission believes that the filing requested by the Companies is essential for the continued pursuit of the EEC and finds that that the Parties' recommendations have merit. Therefore, the Commission orders the Companies insure that the EEC Amendment include the following items:

a) A detailed engineering, construction, and cost estimates for the EEC;
b) A refined project schedule;
c) A complete analysis and support for how development and construction cost for the EEC will be allocated between NPC and SPPC;
d) A complete analysis of the benefits to NPC and SPPC of joint dispatch of the two electric systems;

e) An update of EEC development activities;
f) An update of environmental costs and economic benefits attributed to the EEC;
g) An update of fuel costs including rail transportation costs, status of coal transportation (Northern Nevada Railroad, Union Pacific, other), and progress for securing coal trains and operation and maintenance for these trains;
h) An update of the Financial Plan;
i) An update on the status of all required permits for EEC and related transmission;
j) An update on the status of securing critical resources such as water, coal supply, land, etc;
k) An update on the status of CO₂ regulation and how this might impact cost related to EEC; and

l) An update on the impact of the EEC and the Intertie on the Companies’ planning and operating reserves to include an analysis of reliability issues related to the loss of the Intertie, its impact on the NPC control area, and what steps the Companies propose to address this issue to ensure reliable service in NPC’s and SPPC’s service territories.

The filing shall be in the form of a resource plan amendment and shall be filed in compliance with the resource planning regulations.

173. The Commission views the rate design issues that may result from joint dispatch of NPC’s and SPPC’s systems as a complicated issue that will require a separate and distinct analysis in which a careful consideration of all issues are made in order to determine cost responsibilities for each party and to ensure that there is no subsidization provided from one utility to the other. The Commission does not want to address this issue in the EEC Amendment. If necessary, it can be addressed in a separate filing. However, the Commission does want the Companies to produce an accurate estimate of the benefits and costs to each Company associated with joint dispatch so that a clear determination can be made regarding the net benefits received by each company from the Intertie.

**Should the Companies Use an RFP Process to Select a Coal-fired Resource?**

174. The Commission has considered the BCP’s and NRA’s position that the Companies have not demonstrated that their proposed coal-fired generation resource, the EEC, is a least cost resource and that the Companies should be ordered by the Commission to issue an RFP for comparable baseload resources so that it can compare the bid results from this RFP to the projected cost for the EEC. At this point, it is important to keep in mind the large open position of the Companies (especially NPC), the declining reserve margins in the West, the likely increased pressure on natural gas fired resources in the West due to California’s recent legislative activities related to greenhouse gas emissions, and the magnitude of the savings associated with having a project like the EEC online and on-time. The Companies’ testimony regarding the need for or the efficacy of an RFP process under the current circumstances is convincing. Staff testified that in the
past an all-resources RFP took approximately 13-15 months and generated no contract. The Companies used California as an example stating that the responses to the all-sources RFP included CTs, Wartsila engines and peaking capacity, which do not compare to a super-critical coal unit. The Commission believes that a requirement that the Companies issue an RFP to assess baseload coal generation options would only delay the development of a time sensitive, needed generation resource. The Commission believes that the time required to implement such a process like California's would delay coal generation development efforts by years. Furthermore, the evidence in the record suggests that if an RFP were issued, the likely bidders would be parties that the Companies have spent considerable analysis time with, which ultimately ended in failed negotiations. Finally, the Commission notes that the success of RFPs for long-term resources cannot be gauged solely by the actual contracts that resulted from the RFP. The Commission is aware that many IPP projects fail or are canceled for a variety of reasons. The Commission also notes that sometimes IPPs have sought to renegotiate long-term contracts during the pendency of the contract when economic circumstances change. Hence, the success or failure of the long-term RFP policies in other states cannot be assessed for years, if not decades to come. Therefore, the Commission does not believe that it would be in the best interest of Nevada's customers to delay development of the EEC pending the issuance and processing of an RFP for long-term coal-fired resources.

Factors that the Commission May Consider When Accepting a Resource Plan

175. The Commission has also considered the criticisms made by the BCP that the Companies' Preferred Plan is not the least cost option. The Commission agrees that evidence in the record reflects that the Companies' Preferred Plan, Case 11, is not the least cost plan under base case conditions over a 20-year planning period. The Alternative Plan, Case 13, and Case 4 which relies predominantly on purchases from the wholesale market, both have lower PWRR values for base case conditions. The environmental and societal costs for the Preferred Plan are approximately 1.5% greater than those costs in the Alternative plan, which is an immaterial difference. By regulation, the Companies are responsible for demonstrating how each plan mitigates risk. The
Companies must also identify their preferred plan and justify its choice. By statute, the Commission may give preference to resources that provide the greatest economic and environmental benefits to the State, are consistent with NRS 704.746, and provide levels of service that are adequate and reliable. Neither the regulations nor the statutes contain criteria that require the Commission to accept or the Companies to select the least-cost plan. The Commission is charged with issuing an order accepting the plan as filed or specifying portions of the plan it deems to be inadequate. In this case, the Commission believes that the Companies' Preferred Plan is superior to plans that cost less because it offers fuel diversity benefits, reduces the reliance on the volatile energy markets by reducing the Companies' open position, will result in more predictable and stable rates, and provides a hedge against natural gas price volatility. Furthermore, the Companies' Preferred plan is also consistent with the recommendation in the January 11, 2001, Nevada Electric Energy Policy Committee report to the Governor that it should be the policy of Nevada to put in place a plan that results in an adequate supply of electricity, at a predictable price and with acceptable environmental impacts for the residents of the State. Indeed, these additional benefits would certainly mitigate if not reverse any additional cost. For these reasons, the Commission believes that acceptance of the Companies' Preferred Plan per this Order, is in the best interest of the State of Nevada.

**NCARE Issues**

176. The Commission has considered NCARE's position that NPC's Resource Plan is deficient in its reliance of renewable resources and that this deficiency will result in the unnecessary construction of coal-fired generation capacity; NPC's plan should be more responsive to trends in environmental policy and to costs, risks, and liabilities of potential environmental regulations, especially regulations limiting greenhouse gas emissions; and the practicality of requiring NPC to consider a plan in its Resource Planning efforts like the illustrative plan, included in NCARE's testimony. NCARE does not appear to be familiar with the Commission's encouragement and the

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3 NAC 704.937
4 NRS 704.746 (4)
5 NRS 704.751(1)
Companies’ efforts to comply with Nevada’s RPS. Nevada has one of the most aggressive requirements for renewable resources in the nation. Attempting to displace the very large amount of capacity proposed by NCARE with renewable resources, at least at this point, seems unrealistic, unlikely, and impractical. The Commission notes for future reference that “illustrative plans” that are not supported by accurate and realistic estimates are not helpful to the Commission. The Commission addresses the Companies’ consideration of environmental policy in another section of this Order.

**CO₂ Emissions Issue**

177. The stipulated load forecast coupled with the resource tables indicates that both Companies, and NPC in particular, will need additional baseload resources. There is also a need for the Companies to diversify their generation portfolio so that there is less reliance on natural gas and purchased power. At this time, the only practical and commercially available proven baseload resources that do not use natural gas for fuel are subcritical and supercritical coal technologies. Of these two options, supercritical technologies provide state-of-the-art emission control technology. Further, the Companies are actively engaged in assessing new and emerging emission control technologies, such as REACT, and carbon sequestration for CO₂ emissions. The Companies have indicated that they intend to make allowances in the design of the EEC that will accommodate future emission control technologies. Therefore, the Commission finds that a supercritical coal generation facility as proposed by the Companies is the best option to provide an adequate supply of electricity at a predictable price with acceptable environmental impacts for the residents of Nevada.

178. The Commission acknowledges that there is uncertainty and risk associated with future carbon regulation. This could increase the cost of electricity generated from carbon-based generation resources such as coal, natural-gas, and oil. This risk applies to all of the expansion plans that were considered by the Companies. However, the Commission believes that the Companies, especially NPC, cannot wait for emission regulations to develop and instead must fill large open positions with a limited set of generation options.

179. The Commission has considered BCP’s and NCARE’s position that the Companies did not adequately address the cost and risk associated with future CO₂ emissions regulations. The
Commission disagrees. The Companies presented a complete and thorough analysis of the cost and risk associated with future carbon emissions regulation and fully rebutted these criticisms. There is no way to predict the precise methodology that may be enacted to regulate CO₂ emissions or to estimate the cost of environmental compliance. Further, depending on the type of regulation that is implemented, the Companies may have other options to achieve compliance. For example, if a cap-and-trade program is implemented, the potential cost to customers would depend upon the opportunities the Companies had to reduce CO₂ emissions, and the initial allocation of allowances the Companies would receive. Alternatively, Mr. Maguire noted that a carbon tax could put pressure on retiring older less efficient coal resources in the Companies’ fleet.

180. The Companies provided a full range of estimates for the cost of compliance of all resource plan alternatives. Therefore, the Commission finds that the Companies’ estimates of potential CO₂ emission costs are reasonable, and notes that the Companies will be required to update this analysis in their 2008 Resource Plan Amendment.

Continue to Pursue Additional Generation Options

181. Staff recommended that the Commission order the Companies to continue to pursue other generation options in addition to the EEC. In addressing this issue, the Commission first reiterates its grave concern regarding resource adequacy in the West, NPC’s open position in the 2010 time frame, and its remaining open position even with the addition of the capacity from Phase I of the EEC (this open position will still be around 2000 MW). The Commission believes that it would be wise for NPC to continue to evaluate other resource options that may be available either for the capacity these resources provide or for other benefits. With regard to SPPC, the Commission believes that it makes sense for it to continue to invest in the Valmy option. Therefore, the Commission directs the Companies to continue to investigate other available generation options.

B. Critical Facilities Designation

NPC and SPPC Position

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7 These options should include continued consideration of NPC’s Alternative Plan as an augmentation to the Preferred Plan (i.e., the addition of additional gas-fired resources) other regional coal projects, the re-powering of Mohave, and increased use of mid-term (5-8 years) RFPs.
182. Michael W. Yackira, Executive Vice President and Chief Financial Officer for Sierra Pacific Resources and its subsidiaries, NPC and SPPC, testified in support of NPC’s and SPPC’s request for "critical facility" treatment for the EEC and the associated Intertie as provided by NAC 704.9484.

183. Mr. Yackira explained that capacity shortages were predicted for the Desert Southwest sub-region of the WECC as early as 2009. (Exhibit 5 at 6.) Furthermore, many of the risks inherent with long-term purchased power contracts can be avoided by placing control (design, construction, ownership, and operation) of key projects with the regulated public utility, and thereby bringing oversight of such assets (and their costs) into the regulated environment. When the resource in question is as important to the stakeholders as the EEC is to NPC and SPPC, ownership and control are vital. The EEC will protect reliability by placing control of critical resources in the hands of the utility. Critical Facility designation is thus warranted under NAC 704.9484(2)(a). (Exhibit 5 at 6-7; Exhibit 6 at 6-7.)

184. Mr. Yackira stated that NPC remains heavily dependent on natural gas for its energy supply. NPC’s most recent baseload generation additions, the Chuck Lenzie Generating Station (“Lenzie Plant”) and the Silverhawk Power Plant (“Silverhawk Plant”), were highly efficient natural gas-fired units. NPC has also recently installed Harry Allen 4, a gas-fired CT. Also, NPC continues to have to rely on the purchased power market to meet its summer-time short positions (both capacity and energy). Natural gas is the predominant fuel in the capacity and energy marketplace. (Exhibit 5 at 7-9; Exhibit 6 at 6-7.)

185. Mr. Yackira noted that NPC has recently lost the use of over 200 MW of coal-fired generation from the Mohave plant and faces the potential retirement of Reid Gardner Units 1, 2, and 3 in 2012. Therefore, NPC has a need to improve its diversity of supply. (Exhibit 5 at 7.) Mr. Yackira stated that the EEC will be one of the Companies’ lowest cost generating resources. As a baseload facility, it will be available to displace less efficient generation and more costly purchases. The EEC will support price stability by providing a significant hedge against volatility in the natural gas markets. A secondary benefit of utility-owned generation is the improvement in the ratio of
Company-owned to purchased power generation, which in turn has a positive impact on the financial outlook for the Companies. (Exhibit 5 at 9-10; Exhibit 6 at 7.)

186. Mr. Yackira stated that the proposed Intertie meets the criteria for "critical facility" designation as set forth in the Commission's regulations and orders. Consistent with NAC 704.9484, the Intertie is the delivery mechanism for the output from the EEC. The Intertie shares the reliability, diversity, and retail price stability described above, and will not only allow NPC and SPPC to receive the output from the EEC, but will for the first time connect the two systems physically. The Intertie would thus allow NPC and SPPC to share operating resources to the benefit of customers at both ends of the State. In addition, the Intertie would aid in the development of renewable energy resources and thereby assist NPC in fulfilling its statutory obligations by providing renewable energy developers with a pathway to market. Thus, Critical Facility designation is warranted for the Intertie as well. (Exhibit 5 at 10; Exhibit 6 at 8.)

SNWA Position

187. SNWA witness, Dennis Peseau, supported NPC's Resource Plan; however, this support was conditioned on a cautious approach to the EEC. SNWA recommended that the Commission and parties provide sufficient support and endorsement for the beginning elements of NPC's filed IRP, but that the Commission should stop short of the numerous financial assurances requested by the Company. SNWA recommended that the Commission deny NPC's request for Critical Facilities designation for the EEC and the Intertie unless and until such time as the costs, budget, timing, and rates resulting from completing Phase One can be shown to be reasonable, not unduly burdensome, and in the public interest. (Exhibit 43 at 5.)

BCP Position

188. BCP witness, Kevin Woodruff, presented testimony that the EEC should not receive Critical Facility designation at this time. NPC and SPPC have not shown that the EEC will offer the benefits claimed, and even if it did offer such benefits, it is not clear that constructing the EEC is the only way to get such benefits for NPC's and SPPC's customers. For example, SPPC's customers could also get the purported fuel diversification benefits from the EEC by constructing the Valmy 3
coal unit. Both Companies might get the same, or even superior, diversification benefits from a contract for the output of the proposed White Pine Energy Station. (Exhibit 48 at 35-36.)

189. BCP stated that the Commission should have no preference between utility-owned and non-utility owned generating plants since from the customer's perspective each form of ownership has its own advantages and disadvantages. Rather than favor a particular form in all circumstances, Nevada customers are best-served by making NPC and SPPC compete directly with third parties to offer customers the best possible benefits. (Exhibit 48 at 41-42.)

Staff Position

190. Staff witness, Paul Maguire, testified that Critical Facility designation was premature, given that the Companies are not seeking authorization to construct the facility. The Companies' request in this filing equates to a request to perform an in-depth feasibility study to determine whether a self-build coal plant at Ely is a viable project to undertake, including the issuance of an air permit and a BLM record of decision. Staff noted that the Commission has only designated two other facilities as "Critical Facilities," the Lenzie Plant and the Tracy combined cycle unit. The request for Critical Facility designation is not comparable to the designation of the Lenzie Plant and Tracy facilities. In each of those dockets, the Companies were actually requesting Commission approval to construct the proposed facilities. There are no facilities being requested in this filing to designate critical, therefore the Commission should defer any decision on whether to designate the EEC and the Intertie as Critical Facilities until the Companies make the subsequent EEC filings in which the Companies will seek Commission approval to proceed with construction of the EEC and the Intertie. (Exhibit 56 at 14-15.)

NPC and SPPC Rebuttal Position

191. William Rogers, Treasurer for the Companies, presented the Companies' rebuttal testimony dealing with Critical Facilities designation and incentives. The Companies modified their original requests as follows in their rebuttal case:

a) The Commission should designate the EEC and the Intertie as Critical Facilities in this proceeding.
b) The Companies agreed to forego any incentive ratemaking treatment of the initial $300 million expenditures to be authorized in this case.

c) The Companies agreed to defer until a subsequent proceeding when they request authority to proceed through construction of the EEC and the Intertie, a determination by the Commission of the specific incentives to be awarded for the remaining costs associated with the EEC and the Intertie. (Exhibit 58 at 22-23.)

192. Mr. Rogers opined that the issue under NAC 704.9484 is not whether the Companies need incentive rates in order to achieve or maintain investment grade status, but whether the Companies have demonstrated that the EEC and the Intertie satisfy the regulatory requirements for incentive ratemaking treatment. In this case, the Companies have clearly satisfied the regulatory requirement for incentive ratemaking treatment. (Exhibit 58 at 22-23.)

193. By designating these projects as Critical Facilities, the Commission would send an unequivocal and direct positive message to the investment community at the precise time when the Companies are looking to finance their largest construction effort ever. Such action would be in the best interests of the Companies' ratepayers because, in the long run, capital costs will be lower than if the Commission chose not to grant such treatment in this docket. (Exhibit 58 at 11.)

Commission Discussion and Findings

194. NAC 704.9484 provides that the Commission can designate a facility as critical if it protects reliability, promotes diversity of supply and demand side resources, facilitates the development renewable energy resources, fulfills a specific statutory requirement, promotes retail price stability, or any combination of these criteria. Contrary to the positions of some parties, there is no utility "needs test" for either Critical Facilities designation or financial incentives. The purpose of the regulation is to encourage the Companies to fulfill the public policy objectives described in NAC 704.9484.

195. Nevada now faces a number of challenges in terms of meeting its long-term electricity needs, which are specifically addressed by NAC 704.9484. Capacity reserves in the WECC are declining and by 2010 new resources must be added to maintain adequate reserve margins to assure reliability. As described in NPC's analysis of market fundamentals and
corroborated by Staff and other parties, there is a real prospect of capacity shortages in the Southwest region of the WECC, which includes Southern California, Arizona, and Southern Nevada, as early as 2009. The shortages could be particularly acute in California.

196. Both NPC and SPPC currently have inadequate internal resources to meet their respective loads and must rely on purchase power to fill this open position. Additionally, both NPC’s and SPPC’s coal units are relatively old compared to the most recently commissioned units. In the case of NPC, the situation is particularly problematic. While the addition of the Lenzie Plant in 2006 contributed 1200 MW of new capacity to the system, NPC still has a substantial open position, which it fills through purchased power. The additional capacity from the Lenzie Plant was offset in part by the recent retirement of the jointly owned Mojave Plant. NPC owned 220 MWs. NPC anticipates the retirement of another 340 MW in 2012 with the anticipated closure of Reid Gardner units 1, 2, and 3 in 2012. There is also a question regarding the future of the 2,250 MW Navajo Generating Station in which NPC has an 11.3% share. This coal-fired facility may have to close as early as 2016 due to permitting issues. Thus, without new capacity additions, SPPC’s and NPC’s open positions will grow and can only be offset by a significant increase in utility generation construction and additional power purchases in the wholesale market where it will be in competition with other jurisdictions for scarce generating resources. Given Nevada’s negative experience in such markets, the Commission believes that the construction of new baseload facilities is preferable than having to rely solely on wholesale markets to fill this open position. Further, the Commission believes, given the State’s previous experience during the 2000-2001 Western energy crisis and the importance of new resources to the State, that large strategic capacity additions should be owned and controlled by the Companies.

197. In terms of constructing new baseload capacity, the Commission acknowledges that a gas-fired combined cycle unit is relatively quick to construct, the cost for this capacity on a per MW basis is relatively low, it is relatively less risky for the utility to undertake, and less risky for the utility’s shareholders when compared to a coal-fired facility such as the EEC. However, the cost and availability of fuel to operate gas generation facilities represents a significant price risk when compared to Power River Basin coal. As Staff observed, while gas prices were relatively low at the
time of hearing, the price of natural gas is far more volatile than coal.\textsuperscript{8} The Commission notes that the higher price risk associated with natural gas to run a gas-fired plant is not borne by the Companies, but rather is borne by their ratepayers since fuel and purchased power costs incurred by the Companies are passed on to customers on a dollar-for-dollar basis through deferred energy accounting.

198. With respect to demand for natural gas, almost all new capacity, either utility or non-utility generation, constructed in the country over the past decade has been natural gas capacity. The increased demand for gas has been reflected in the price of natural gas. Recent legislative actions in California suggest that it plans to rely heavily on natural gas generated electricity to meet its future needs. This will place even greater pressure on the volumes of gas demanded. While there are a number of promising new resources in Alaska and the MacKenzie Delta in Canada, the timing for these resources is not yet available and their cost remains uncertain. Staff indicated that these factors could result in future natural gas prices that are higher than the prices now being forecasted given that many of the price forecasts assume the timely completion of these projects. Consequently, an increased reliance on natural gas generators for baseload generation must be very carefully considered from the standpoint of both self-generation and purchased power alternatives. Based not only on the record in this proceeding, but the experience of deferred energy and Energy Supply Plan proceedings over the past two years, the Commission has serious reservations about increasing NPC’s and SPPC’s reliance on natural gas to power its baseload plants.

199. As a whole and separately, the major components of the NPC’s and SPPC’s plan address the challenges described above. Even with the addition of renewable energy and DSM resources that will account for 20 percent of energy needs by 2015, additional capacity will still be needed. Nevada has a vested interest in insuring, to the extent that it can, that this capacity is constructed in a timely manner and if possible, is not fired solely by natural gas. The EEC will both

\textsuperscript{8} Exhibit 96, which was proffered by NCARE, showed that the closing price for gas at Henry Hub Spot Market was $3.63 on September 29, 2006. The Commission notes that prices since that date have risen substantially. The price for deliveries during December 2006, at Henry Hub on the close of trading on Thursday, November 2, 2006, was $7.81. For 2007, the forward price curves ranged from a low of $7.729 for deliveries in April 2007, to a high of $9.013 for deliveries in December 2007. http://futures.tradingcharts.com/marketquotes/NG.html (accessed November 2, 2006).
add additional baseload capacity and reduce both SPPC’s and NPC’s reliance on natural gas and purchased power.

200. The Intertie will promote reliability, promote diversity of supply resources, assist with the development of renewable resources, and promote retail price stability. It is the delivery mechanism for the output from the EEC to both Northern and Southern Nevada. In addition, the Intertie will aid in the development of renewable energy resources by allowing electricity generated by non-solar renewable resources in Northern Nevada to be delivered to Southern Nevada and electricity generated by solar resources in Southern Nevada to be delivered to Northern Nevada. Further, the Intertie will allow for the development of wind resources in Eastern Nevada to both Northern and Southern Nevada. Therefore, the Intertie will assist both NPC and SPPC to meet its statutory obligations by providing renewable energy developers with a pathway to market.

201. The Commission rejects the arguments that Critical Facilities designation is premature given that there are no facilities to designate. The timely completion of the EEC and Intertie is necessary to address the projected capacity shortage and price volatility in natural gas and purchased power markets. Both factors contributed to the western energy crisis of 2000-2001 and avoiding a similar crisis in the coming years is critical to sustaining growth in southern Nevada. The EEC will be the second largest energy project in history of Nevada and will require large sums of capital and external financing. To the extent that the regulatory risk associated with a project of this magnitude can be reduced, it may ensure that NPC and SPPC have access to capital markets at attractive rates. Critical Facility designation at this time helps ensure that the EEC and Intertie are constructed and serving Nevada by 2011. Therefore, NPC’s and SPPC’s request to designate the EEC and the Intertie as Critical Facilities pursuant to NAC 704.9484 is approved.

202. The Companies will forego any incentive ratemaking treatment of the initial $300 million expenditures authorized in this case. The Companies agreed to defer, until the EEC Amendment, when the Companies will request authority to proceed through construction of the EEC and the Intertie, a determination by the Commission of the specific incentives to be awarded for the remaining costs associated with the EEC and/or the Intertie.
203. With designation of a facility or facilities as critical, the utilities are eligible and may request financial incentives which would be included in rates in the utilities' next general rate cases. The incentives are not limited and may include: earning an enhanced return on equity ("ROE") over the life of the facility, including construction work in progress ("CWIP") in the general rates, and placing costs incurred to construct the facility in a regulatory asset account. The Commission has recognized in the past as it does now the importance of accounting methodologies to reduce regulatory lag and assist in the construction of major utility plant additions in this State.

204. Prior to the adoption of NAC 704.9484(3) the Commission traditionally excluded CWIP from rate base. For good cause shown, it had deviated from this practice. In 1977, the Commission authorized SPPC to include the North Valmy generating station CWIP into rate base when total expenditures exceed $27.7 million. SPPC estimated the total construction cost to be $200 million. The Commission cited rationale similar to that professed by NPC and SPPC in these proceedings, intangible benefits associated with higher quality earnings and fuel diversity. In 1979, SPPC sought and the Commission authorized SPPC to include $31.966 million of Valmy 1 and any common facilities CWIP in to rate base.

205. While Valmy Unit No. 2 CWIP was excluded from rate base, the Commission granted SPPC's request to continue to accrue AFUDC for Valmy Unit No. 2 and defer recording Valmy Unit No. 2 depreciation, until rates including the facility were effective.

206. The first time incentive treatment under the new resource planning regulations, in particular, the incentive portion of the regulations, was requested by a utility was in consolidated Docket Nos. 04-6029 and 04-6030. The Commission granted a ROE adder for the accumulated plant balance for the Moapa facility (re-named Chuck Lenzie) along with CWIP. The Commission limited the amount of facility construction costs eligible for incentives to $367.6 million. Incentive

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9 Nevada Administrative Code 704.9484(3) (May 25, 2004).
treatment was not granted to the funds expended to buy the partially built facility, only to actual
construction costs spent to finish the facility.

207. In Docket No. 05-8004, the Commission approved SPPC’s request to construct a 514
MW CC at the existing Tracy facility. SPPC was awarded CWIP along with a ROE adder of 1.5%.
The Commission stated that “while incentives are important especially in light of the State’s energy
policy, they should not be given simply because a utility is doing its job.” Docket No.05-8004,
¶196 (Dec. 14, 2005.) The Commission felt that this particular combination of incentives would
mitigate the effect of regulatory lag as well as keep SPPC neutral with respect to this major
investment. It would send a positive message of Commission support for SPPC to the credit rating
agencies that monitor it, aiding SPPC in its goal of reaching investment grade status.

208. The cost-estimate provided by NPC and SPPC in the present dockets for Phase 1 of
the EEC including the North-South intertie is $3,775,144,000. Staff believes that after the
engineering studies are completed there may be as much as a 25% increase regarding costs.
Without having definitive cost estimates and more specific construction plans in front of it, the
Commission believes that the granting of specific incentives at this time would be premature.

209. The Companies have agreed to defer the request for specific incentives until the EEC
amendments in 2008. At that time, NPC and/or SPPC will have to petition the Commission in their
resource plan amendments for the approved amount of costs to be deemed eligible for incentive
treatment. The granting of incentives requires reasoned and careful application and a balancing of
the impact on rates to consumers with the need to incent construction of utility-owned facilities.
Different incentives may be given to different aspects of a particular project. The Companies will
also show in their following general rate applications that all of the monies spent were prudent and
reasonable.

210. One of the more frequently granted incentives is CWIP. Granting CWIP for the EEC
can only occur after an appropriate showing by the Companies in the 2008 Amendments. The
granting of CWIP at that time will increase the ability to finance this type of extraordinary capital
expenditure by enhancing internal cash flow. However, the rate impact of a hybrid or future test
year if adopted by the Nevada Legislature must be considered in the application of this type of
incentive. Another form of financial incentive that had been used by the Commission is an
enhanced ROE. Granting an enhanced ROE over the lifetime of a facility is another rate making
incentive available to critical facilities. The granting of such an incentive should be carefully
applied and may be applied to one aspect of the project but not another when the Companies make
their application in 2008. Other accounting mechanisms such as the timing of depreciation and the
creation of a regulatory asset will also be available to the Commission to ensure a needed facility
designated as critical will be built on time.

211. While the Companies have agreed to defer the determination of the specific
incentives until the EEC Amendment, when further authority is requested with respect to the EEC,
the Commission believes it is important to maximize the benefits from the Critical Facility
designation which it has made in these dockets. Consequently, although specific financial
incentives would not be addressed until the time of the Companies’ subsequent filing, these benefits
should start immediately as the financial community takes the Critical Facility designation into
account even at this early date looking forward to the large capital requirements of the EEC. It is
also important to identify now other elements of the incentive with respect to the RPS. Therefore,
while the Commission will finally authorize the package of incentives in connection with the
Critical Facility designation at the time of the Commission’s order on the EEC Amendment, the
Commission recommends that the incentives should include at a minimum, the following:

For NPC and SPPC for the EEC:

- 0.125 percent equity adder for any year compliant with non-solar RPS
- 0.250 percent equity adder for any year compliant with solar RPS
- 0.125 percent equity adder for any year 5% over non-solar RPS
- 0.250 percent equity adder for any year 5% over solar RPS

For NPC for the EEC:

- 0.250 percent equity adder on Unit 1 if commercial before 6/01/11
- 0.250 percent equity adder on Unit 2 if commercial before 6/01/12
For SPPC for the EEC:

- 0.125 percent equity adder on Unit 1 if commercial before 6/01/11
- 0.125 percent equity adder on Unit 2 if commercial before 6/01/12

212. The Commission believes that the development of wind resources will reduce the volumes of natural gas used to generate electricity in Nevada. Thus, the Commission was pleased to hear that NPC anticipates having a wind project completed by the end of 2008. Further, testimony by NCARE suggests that wind generation may reduce the number of hours that gas-fired units will need to be operated and thereby natural gas will be conserved. Therefore, the Commission designates as Critical Facilities the first 200 MW of utility-owned and/or utility equity partnered wind generation discussed in paragraph 317 below. Given the nexus between natural gas generation and wind generation, the Commission believes that incentives for these units should be tied to the new peaking units planned for the Clark Station discussed in paragraph 229 below. While the capacity associated with these peaking units may be necessary to reinforce reliability, any wind generated electricity reduces our dependence on natural gas. Therefore, the Commission approves incentives for the second phase of the Clark Station peaking units that include but is not limited to the following:

- 0.25 percent equity adder for 75 MW utility-owned and/or utility equity partnered wind in service by 12/31/08
- 0.25 percent equity adder for 150 MW of utility-owned and/or utility equity partnered wind in service by 12/31/09
- 0.25 percent equity adder for 200 MW of utility-owned and/or utility equity partnered wind in service by 12/31/10
III. Phase III Issues: NPC Specific Issues

A. Clark Station Peaking Units

NPC Position

213. NPC witness, John Lescenski, Manager of Generation Asset Performance Management for NPC and SPPC, sponsored the sections of NPC's IRP addressing the proposed Clark Station Peaking Units. (Exhibit 23 at 1-2.)

214. Mr. Lescenski stated that NPC proposes to construct 600 MW of natural gas-fired peaking power generation at the existing Clark Station and that this generation will be installed in two blocks with approximately 400 MW installed prior to the summer of 2008 and approximately 200 MW installed prior to the summer of 2009. The estimated cost for the installation of these CTs is between $384 million and $394 million (without AFUDC). The “quick start” CTs will provide critically needed peaking capacity to NPC’s system. In addition, the operating flexibility of these CTs will allow NPC to follow variations in the output of intermittent resources, such as wind generation. Given the low overall capacity factor of NPC’s load and the extreme peaks seen in some hours, these CTs are ideally suited to serve NPC’s load profile. (Exhibit 1, Volume VI at 19.) Information regarding the proposed Clark CTs is contained in Technical Appendix II (Volume 2 of 2, Item 13). (Exhibit 23 at 2.)

215. In response to clarification questions, Mr. Lescenski indicated that the proposed peaking resources are being placed at Clark Station for several reasons. The air emissions from the retired Clark Units 1, 2, and 3 can be netted against the proposed peaking units. From a permitting perspective there is a provision called a contemporaneous change that allows a user to build new units without increasing emissions, and it is an easier permit to obtain than having to go through a prevention of significant deterioration permitting process that would be necessary if it were a greenfield site. He also indicated that one of the reasons NPC is using the Clark Station is that it can take advantage of the existing transmission infrastructure such as the switchyard and substation with only small modifications to these transmission facilities. (Tr. at 1000.)
Staff Position

216. Staff witness, Jon Davis, recommended that the Commission approve the proposed Clark Station Peaking Units. He also recommended that the Commission require NPC to analyze the cost effectiveness of supplying these units with gas from the El Paso transmission system in addition to the Kern River pipeline and to include this analysis in its next Energy Supply Plan. (Exhibit 52 at 44.)

217. Mr. Davis listed the advantages associated with the aero-derivative turbines proposed by NPC as compared to frame type turbines. (Id. at 44-45.)

218. Mr. Davis stated that NPC, in general, should issue an RFP for generation resources in order to compare third-party bids. However, the possibility of a very limited availability of purchased power resources in 2008 warrants that the Commission forgo a requirement for an RFP for these resources and instead approve the project as proposed by the NPC. In addition, it is likely that an IPP would not be competitive for this project for the following reasons:

   a) In order to purchase an equivalent resource from an IPP, the IPP would have to construct a new facility. The cost of construction for the IPP should be similar for either NPC or the IPP. However, the total project cost is expected to be lower for an NPC self-build option due to the existing infrastructure available at the Clark Station.

   b) Any IPP site would likely be a greenfield site that would require additional land, new transmission, and water. These resources already exist at Clark Station. Since NPC needs this resource in 2008, it is unlikely that an IPP could be developed at a new site in this time frame; and

   c) NPC will not require additional staff to operate this site. (Id. at 45-46; Attachment JDF-22.)

219. Mr. Davis stated that the peaking units proposed by NPC are better generation options than economy energy purchases and a combined cycle generating unit. (Id. at 46-49.)

220. Mr. Davis also disagreed with NPC’s statements that it should not evaluate an option to supply the Clark Peaking Station off a Southwest Gas tie to El Paso Gas. NPC should evaluate the El Paso option to determine if it is in the best interest of the raters to bypass this investment which would allow the Clark peaking units to access the El Paso Pipeline. He identified a number
of transportation advantages that the El Paso pipeline offers which include ample spot transportation capacity, an alternative supply to Kern River and direct access to another source of gas supply for the Peaking units. (Id. at 51-52.)

**BCP Position**

221. BCP witness, Kevin Woodruff, explained that with respect to the proposed peakers at Clark in 2008 and 2009, NPC failed to make a convincing quantitative case that installing these peakers is in the best interest of its customers. He further explained that NPC’s own analysis suggest that the CTs are the highest cost resource of the options that NPC considered and NPC did not show that the Clark Station is the best site for new peakers as compared to another location. (Id. at 3.)

222. Mr. Woodruff stated that NPC relied upon a qualitative argument to support its case that the proposed CTs at Clark Station are the best resource of the options that it considered. The qualitative arguments that NPC made to support its position include:

   a) The proposed CTs provide tremendous operating flexibility as they can be quickly started and stopped to follow changes in system load or market conditions with minimal start-up costs as opposed to combined cycles which do not have this flexibility;

   b) Expansion plans that rely on additional spot market purchase to replace the CT capacity do not satisfy the system reliability requirements; and

   c) Most standard market products cannot follow rapid changes in system load like the proposed CTs and those that can are difficult to find.

Further, NPC’s arguments about the relative value of the CTs are partially persuasive. He added that he agrees with NPC, that some amount of peakers using an aeroderivative technology, are likely to be a very good addition to NPC’s portfolio. (Id. at 4-5.)

223. Mr. Woodruff recommended that the Commission authorize NPC to construct only the approximately 400 MWs of “quick start” CTs at the Clark Station scheduled to be in service 2008, but defer approval of the construction of the additional 200 MW of CTs scheduled to be in service in 2009 until the Companies re-file a revised IRP in 2007. (Exhibit 77 at 2.)
224. Mr. Woodruff explained that the Commission should permit NPC to continue efforts to build the CTs intended to be in service in 2008 because he does not believe that peakers could be added in 2008 unless the Commission authorized their construction this year. (Id. at 7.) With regard to the 2009 peakers, he stated that as a general principle, he believes that NPC should be required to test the value of its own proposed resources against those that could be offered by third-parties pursuant to an RFP for long-term resources (he indicated that this should have been done for the 2008 peakers as well). In addition, NPC has time to solicit peaking proposals from the market for comparison to the third block of proposed Clark Peaking CTs before authorization is required for a 2009 resource. (Id. at 7.)

**SNWA Position**

225. SNWA witness, Denis Peseau, indicated that SNWA generally endorses moving forward with the 600 MWs of quick start CTs at Clark Station. (Exhibit 43 at 6.)

**NPC Rebuttal Position**

226. Mr. Lescenski he disagreed with Mr. Woodruff's contention that NPC failed to make a convincing case that the peakers at the Clark Station are in the best interest of its customers. There are two primary reasons that the Clark Station is the best site for the peakers. First, the retirement of the Clark Units 1, 2, and 3 allows additional units to be built and operated at the facility, under a netting of the previous emissions from these units. Second, Clark Station provides a site close to the load that does not require import capacity and is not affected by transmission constraints. Clark Station is a manned facility with an existing switchyard and plant infrastructure that will allow these units to be operated without additional operating and maintenance personnel. (Exhibit 89 at 5-6.)

227. Mr. Lescenski also disagreed with Mr. Woodruff regarding his position that a decision regarding the CTs scheduled to be on line in 2009 could be delayed until other options were considered by NPC. NPC is concerned that an extensive RFP like the one suggested by Mr. Woodruff could delay the proposed in service date of 2009 to a timeframe beyond the peak season in 2009. (Id. at 7.)
Commission Discussion and Findings

228. Construction of the CTs at the Clark Station clearly gives NPC an advantage because of the cost savings attributed to the peakers being installed at the existing NPC generating site, the Clark Station. There are only three existing sites available in the Las Vegas Valley for this project: Clark, Harry Allen, and Sunrise. With respect to the Harry Allen and Sunrise, both locations would require new air source permits. Additionally, there are space constraints at Sunrise. The Clark site has the following benefits: an existing transmission infrastructure, existing operations, maintenance workforce and infrastructure, an existing water supply, permitting advantages over a greenfield site, and transmission advantages in that it will not tie up transmission import capacity or contribute to a transmission constraint within NPC's system. In addition, there is no evidence that there is existing non-company owned generation in NPC's control area that has similar characteristics to those of the proposed peaking units. For these reasons, the Commission rejects BCP's recommendation to defer approval of the 2009 CT until NPC's proposed resource can be compared against those that could be offered by a third-party using an RFP process.

229. The Commission agrees with the parties that the proposed Clark Station Peaking Units provide critically needed peaking capacity to NPC's system, appear to be ideally suited to serve NPC's load profile, will provide operating flexibility to NPC's operators, have advantages associated with the proposed aero-derivative turbines over frame-type turbines, and will provide a better resource option than economy energy purchases and a combined cycle generating unit. Therefore, the Commission approves NPC's request to construct 600 MW of nominally rated quick start CT peaking units at Clark Station at a cost of between $394-$398 million, with approximately 400 MWs of peaking capacity to be installed prior to the summer of 2008 and approximately 200 MWs of additional peaking capacity to be installed prior to the summer of 2009.

230. The Commission believes that Mr. Davis' recommendation that NPC be ordered to perform an economic evaluation to determine the cost effectiveness of investment on Southwest Gas Corporation's system to allow access to the El Paso Pipeline has merit based upon the potential benefits identified by Mr. Davis. Therefore, NPC is ordered to complete the economic evaluation in
collaboration with Staff and BCP and submit a copy to the Commission within 12 months from the date that this order is issued.

B. Environmental Equipment Upgrades at Reid Gardner Generating Station

NPC Position

231. NPC witness, Mr. Pottey, stated that simulations using PROMOD, a production cost model, were used to evaluate the economic impacts associated with the proposed improvements at Reid Gardner. The results of the analysis confirmed that the benefits associated with the continued operation of the Reid Gardner Units 1, 2, and 3 substantially outweigh its costs. The payback period for the $84 million in improvement costs is slightly over one year. (Exhibit 27 at 14.)

232. NPC witness, John Lescenski, sponsored NPC’s request for approval of the Reid Gardner Environmental projects. (Exhibit 23 at 4.)

233. Mr. Lescenski stated that NPC seeks authorization to install baghouses on Reid Gardner Units 1-3, gas igniters on Reid Gardner Units 1-4, and a rotating over-fired air system on Reid Gardner Unit 4. The installation of this equipment will allow these units to continue operation in compliance with current environmental air quality regulations. Without the installation of this equipment, the Reid Gardner Units cannot operate without violating environmental regulation. Further, if these improvements do not receive Commission approval in time to advance into construction in 2008, the Reid Gardner units will need to shut down. A description of the issues involved in NPC’s request for approval of the Reid Gardner environmental projects and summary of each project requested by NPC is provided in Exhibit 1, pages 23-35. (Exhibit 1, Volume VI at 24.)

234. Mr. Lescenski stated that NPC’s economic analysis supports the installation of the environmental equipment at Reid Gardner and the payback period for the investment in environmental equipment is a little over one year. (Id. at 25-26.)

Staff Position

235. Staff witness, Jon Davis, provided Staff’s recommendations and analysis regarding NPC’s request for Commission approval of environmental equipment installations at Reid Gardner Generating Station at a total cost of $84 million. (Exhibit 52 at 1.)
236. Mr. Davis concurred with NPC’s economic analysis and recommended that the Commission approve $84 million for the construction of the environmental improvements for Reid Gardner Units 1-4. Commission approval should be subject to confirmation that NDEP will require the construction of these environmental improvements. (Id. at 55.)

Commission Discussion and Findings

237. NPC is recommending that environmental equipment costing $84 million be installed on Reid Gardner Units 1-4 in order to prevent the units from being shut down in 2008. Staff supports NPC’s request subject to confirmation that NDEP will require the construction of these environmental improvements. No other Parties provided testimony regarding this issue. The Commission finds that the economic analysis completed by NPC supports the installation of the requested environmental equipment on Reid Gardner Units 1-4. Therefore, NPC is authorized to spend $84 million for environmental equipment for Reid Gardner Units 1-4 if required by NDEP.

C. Decommissioning Costs for Clark Units 1-3

NPC Position

238. NPC witness, John Lescenski, indicated that it has revised its estimate of $30 million for the decommissioning costs for Clark Units 1-3 and noted that the $30 million was previously approved by the Commission. NPC is now requesting approval for a total of $37 million to decommission these units. (Exhibit 23 at 3; Exhibit 1, Volume VI at 12.)

Staff Position

239. Staff witness, Paul Maguire, stated that NPC requested and received formal bids from contractors for the decommissioning of Clark Units 1-3. He indicated that based upon responses to Data Requests received from NPC that the expected cost for the decommissioning of these units is expected to be about half of the original estimate. (Exhibit 74 at 4, Attachment PRM-3.)

240. Staff recommended that the Commission approve the decommissioning of Clark Units 1-3 at an expenditure level of up to $17 million. (Id. at 5.)
BCP Position

241. Mr. Pous recommended that NPC’s request for approval of $37 million to decommission Clark Units 1-3 should be denied by the Commission. He explained that NPC failed to justify the cost level for which it seeks approval and that supplemental responses to Data Requests indicate that there has been a significant reduction in the estimated cost to decommission these units. He also indicated that NPC is seeking decommissioning costs for items that appear to be either the cost of the new CT installation at Clark Station or the potential cost of removal associated with other equipment outside the production area. (Exhibit 81 at 17-20.)

242. Mr. Pous stated that the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USA") recognizes that the cost incurred to remove retired facilities is considered part of the replacement activity. The USA defines "replacement" as a situation "when not otherwise indicated in the context, means the construction or installation of electric plant in place of property retired, together with the removal of property retired." He asserted that the activity for which NPC seeks decommission treatment fits the USA definition of replacement. (Id. at 18-19.)

NPC Rebuttal Position

243. Mr. McDonald disagreed with Mr. Pous’s position that the decommissioning costs for the Clark units appear to be either a cost of new installation or potential cost of removal associated with FERC accounts outside of the production area. The costs to decommission the Clark units are strictly removal and remediation related, and he asserted that Mr. Pous is wrong in claiming that these costs are in any way related to site preparation for the new peakers. (Exhibit 88 at 10-11.)

244. Mr. McDonald stated that NPC does not support inclusion of these costs as part of the new construction at Clark and to do so would perpetuate intergeneration inequity. Mr. Pous’ proposal would result in the costs incurred to remove units that were first put in service in 1955 to be recovered from customers in the 2030s who did not receive the benefit from these generators. (Id. at 11.)
245. Mr. Lescenski agreed with Mr. Maguire’s recommendation that NPC’s request for $37 million for the Clark decommissioning be reduced to $17 million. Actual bids for the decommissioning work were recently received and through commercial negotiations, the projected cost of decommissioning is estimated to be approximately half of the original $37 million estimate. (Id. at 9.)

Commission Discussion and Findings

246. The Commission is convinced by NPC’s explanation that the cost to decommission the Clark units is appropriately designated as a decommissioning cost and that the accounting proposed by the BCP would result in intergeneration inequity. The Commission finds the current estimate, $17 million, to be reasonable as this estimate is based upon actual bids that were received by NPC for the decommissioning work. Therefore, NPC’s modified request for approval to decommission Clark Units 1-3 at a cost of $17 million is approved.

D. Transmission Issues

NPC Position

247. NPC witness, Brian Whalen, Manager of the Transmission Planning Department for the Companies, sponsored the transmission planning section of NPC’s 2007-2026 IRP. (Exhibit 34 at 1-2.)

248. Mr. Whalen identified the Phase III transmission projects for which NPC is requesting specific Commission approval. These projects include:

a) The East Valley Area Master Plan ("EVAMP") project which consists of the construction of two new 500/230 kV substations, the proposed Sunrise 500/230/138 kV substation and associated infrastructure ("Sunrise Option") and the proposed Equestrian North 500/230 kV substation and associated infrastructure ("Equestrian Option"), and the expansion of the existing Northwest substation;

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15 A full description of these projects and the technical analyses supporting their selection are included in Exhibit 1, Volume VI, Transmission Planning section and Technical Appendix II, Volume 3 of 3. The projected Action Plan period expenditures for these transmission facilities are listed in Table AP-1 of Exhibit 1, Volume VI.
b) The Northwest Las Vegas Area Routing and Siting Master Plan ("VARS") Project substations which include five 230/12 kV substations along the Harry Allen-Northwest 230 kV line corridor and seven 138/12 kV substations along the proposed Thunderbird-Northwest line corridor. The VARS Project substations and lines are specifically required to serve projected load growth in the northern Las Vegas Valley;

c) The West Henderson improvement projects which are necessary to reliably serve load growth in the Henderson Area;

d) The Sinatra substation which is necessary to serve projected load growth in the Las Vegas Strip area;

e) Additional reinforcement of the 230 to 138 kV grid with new transformers at Iron Mountain, Northwest, Arden and Brooks substations;

f) A rebuilding of the Clark substation in order to accommodate the proposed CTs planned to be installed at that location;

g) Approval of WestConnect membership costs;

h) Approval of specific regional planning participation costs;

i) Approval of expenditures to begin permitting proposed 230 kV circuits planned into the Highland substation from the Sinatra, Sunrise, and Brooks substations; and

j) Approval to proceed with the design and construction of an interconnection with Valley Electric Association transmission system. NPC's request is pursuant to its Open Access Transmission Tariff and the Federal Power Act. (Id. at 3-6.)

249. Mr. Whalen explained that NPC is proposing to build the Sinatra substation instead of the minimum required facilities for Project CityCenter because it has requests for transmission service expansion from numerous parties in the Las Vegas Strip and Downtown area. With the projected loads from these requests, NPC will exceed the capacity of its existing transmission system in the next two to four years, and it is necessary to begin constructing the 230 kV infrastructures prior to that time. The risk of the capacity not being needed is small and limited to the installation of facilities earlier than they would otherwise be needed. Given the number of publicly announced projects along the around the Strip, it is extremely unlikely that this capacity
will not be needed. Further, there is significant risk if large new 230/138 kV transmission sources are not placed in the Las Vegas core. This risk is an inability to serve additional load or an inability to reliably serve load. (Id. at 6-7.)

250. Mr. Whalen stated that NPC has performed technical analysis to confirm that the facilities for which it is requesting Commission approval are part of an optimal plan. This information is included in the Transmission Plan section of NPC's Technical Appendix submitted with its IRP. (Id. at 8.)

251. Mr. Whalen explained that NPC is not addressing cost allocation to third parties in this proceeding. He indicated that all cost allocation will be done in accordance with the policies of the Commission and the FERC. (Id. at 10.)

252. Mr. Whalen supported NPC's request for Commission approval of expenditures for continued participation in WestConnect and for regional studies and sponsored the portions of NPC's IRP related to these expenditures. (Exhibit 34 at 2; Exhibit 1, Volume VI at 153-157.) With regard to the WestConnect expenditures, NPC is requesting that the Commission approve $166,000 during the Action Plan period to maintain involvement and membership in WestConnect. With regard to the regional studies, NPC is requesting approval to expend $350,000 for regional planning costs relating to the Frontier Line Transmission Development Association. (Exhibit 1 at 16.)

253. With regard to the expenditures for participation in WestConnect, Mr. Whalen noted that the Commission authorized NPC to join WestConnect in November of 2005. WestConnect is a group of southwest transmission-providing utilities that have agreed to work collaboratively to assess stakeholder and market needs and to investigate, analyze, and recommend cost-effective enhancements to the western wholesale electricity market. (Exhibit 1, Volume VI at 157.)

254. Mr. Whalen stated that NPC is requesting funds for the regional studies to perform feasibility analysis for long-term strategic planning of major western interconnection proposals such as the Frontier Line. These projects differ from NPC's normal planning as they are long lead time joint projects, they affect the operation of the entire Western Interconnection, the transmission system in the Western United States, and they involve numerous other entities. (Exhibit 34 at 5.)
The expenditures are required in order to determine if the Frontier Line and other regional transmission projects are feasible and beneficial in comparison to other resource alternatives available to SPPC and others participating in the feasibility analysis. (Exhibit 1, Volume VI at 154-155.)

Staff Position

255. Staff witness, Paul Maguire, provided testimony addressing NPC’s request for approval of transmission facilities to be located in Clark County. (Exhibit 74 at 1-2.)

256. Mr. Maguire specifically recommended that the Commission approve the following items with respect to these transmission facilities:

a) The second Northwest 500/230 kV transformer component of the EVAMP project. The Commission should defer approval of the Sunrise and Equestrian components until a later resource plan filing. The three-year Action Plan expenditure amounts for the Northwest 500/230 kV transformer totals $28.5 million;

b) The VARS project and authorize expenditures for this project of $170.8 million during the three-year Action Plan period;

c) The Southeast No. 1 230/138 kV substation and the West Henderson 230/12 kV substation components of the West Henderson Improvement projects. There is no need for the Commission to approve the construction of the Southeast No. 2 230/12 kV substation in this IRP. The Commission should approve an Action Plan expenditure amount of $37.1 million with the understanding that the 2007 dollar amount includes $100,000 for permitting activities associated with the Southeast No.2 230/12 kV substation;

d) The Sinatra substation and related transmission infrastructure as outlined in the IRP filing, recognizing that Staff does not agree with the cost allocation methodology NPC is recommending in Docket No. 06-06007. The Commission should only approve an Action Plan period expenditure amount of $98.7 million, not the $109.3 million requested by NPC;

e) NPC’s request for the following: (1) transmission upgrades necessary to support the installation of the new Clark Station CTs; (2) transmission upgrades at the Arden substation; (3) transmission upgrades at the McDonald substation; and (4) transmission upgrades needed for the VEA
interconnection. Expenditures during the three-year Action Plan period for these projects total $24.4 million ($11.2 million in 2007, $11.1 million in 2008, and $2.1 million in 2009);

f) NPC’s request to perform the Clark 230/138 kV bank No. 6 transformer change out. The estimated cost of this project is $4.1 million with only $200,000 falling within the Action Plan period; and

g) NPC’s request to initiate studies, permitting, and land acquisition for Sunrise to Highland, Highland to Sinatra, and Highland to Brooks 230 kV transmission lines. The estimated cost to perform these studies is $1 million.

257. Mr. Maguire stated that NPC is not seeking approval for any expenditures associated with the WPEA, GBT projects, or the Nevada Solar One interconnection at this time. It is not appropriate for the Commission to approve the construction of any facilities for third-parties until after the utilities have executed contracts with these third-parties. Because Nevada utilities have experienced problems with some entities that subscribed to capacity and then later defaulted on their commitments, it is important for the Commission to assess credit/collateral terms in these contracts before it approves construction of any facilities for third-parties. (Id. at 15-16.)

258. Mr. Maguire stated that he had concerns regarding NPC’s request for approval to construct the Sunrise Option which is a transmission project included as part of the EVAMP project. His concerns center on the timing and need for the Sunrise Option and NPC appears to have the ability to defer this project until 2013. (Id. at 19.) NPC has not performed an economic analysis to determine whether the Sunrise Option could be deferred until 2013 pending determination of the availability of capacity from internal IPPs or from other NPC internal units. He clarified that he is not implying that NPC should rely solely on serving load in the 2010 to 2013 time period with purchases from internal IPPs or other resources, but that NPC should investigate its available options before it constructs new transmission facilities that will ultimately be paid for by its customers. (Id. at 20-21). The worst case scenario would be for NPC to construct the Sunrise Option with the cost of this transmission project going into rate base, NPC ends up signing contracts with Reliant and Mirant, the Sunrise Option facilities are not used until 2013, and ratepayers end up paying for the project three years before it is needed. (Tr. at 1026.)
259. Mr. Maguire added that given the changes that can occur during the course of the next two years, he believes that Commission approval to construct the Sunrise Option would be better addressed in a subsequent filing. (Exhibit 74 at 25.)

260. Mr. Maguire objected to Commission approval of the Equestrian Option which is also one of the transmission facilities included as part of the EVAMP Project. This project is not scheduled to be in service until 2014, and there are no planned expenditures for this project in the Action Plan in NPC’s Application. No reason exists for the Commission to approve this project at this time and he recommended that the Commission defer approval of this option until a later resource plan filing. (Id. at 26.)

261. With regard to the VARS project, Mr. Maguire stated that this project is needed to expand the load serving capability in the northern Las Vegas area. Staff’s forecasts of growth for this area support additional investment in transmission and distribution equipment. (Id. at 27.)

262. Mr. Maguire provided testimony addressing NPC’s request for Commission approval of expenditures for continued participation in WestConnect and for regional planning studies related to the Frontier Line Project. (Exhibit 74 at 2.)

263. With regard to NPC’s request for Commission approval for expenditures for regional planning studies, Mr. Maguire stated that it is imperative that NPC participate, and in some cases, take a leading role in the regional projects that are currently being evaluated for the Western Interconnection. Failure to participate in these studies would leave NPC and its ratepayers at a severe disadvantage as issues that would help or hinder Nevada would go undiscovered. (Id. at 38.) He recommended that the Commission approve NPC’s request for Commission approval of $350,000 to participate in regional planning activities. (Id. at 38.)

264. With regard to NPC’s request for Commission approval for expenditures for continued participation in WestConnect, Mr. Maguire recommended that the Commission approve NPC’s request to spend $166,000 during the Action Plan period to continue its participation and involvement in WestConnect. (Id. at 39.)
BCP Position

265. BCP witness, Dale Stransky, provided testimony regarding some of the transmission facilities for which NPC is requesting Commission approval of in its Application. (Exhibit 79 at 3.) Mr. Stransky’s specific recommendations include the following:

a) No opposition to the approval of the $109.3 million in expenditures for the Sinatra substation and related transmission infrastructure. However, the BCP reserves its right to refute and/or contest the proposed cost responsibility to ratepayers related to the over-capacity portion of the facilities in Docket No. 06-06007;

b) Accept the request to expend $24.4 million for transmission upgrades regarding projects related to Clark Station, Arden and McDonald substation, and Valley Electric Association interconnection;

c) Accept the request to expend $350,000 to complete Regional Transmission Planning Studies;

d) Accept the request to expend $166,000 to maintain involvement and membership in WestConnect; and

e) Accept the request to expend $1 million to initiate studies, permitting and land acquisition for the Sunrise to Highland, Highland to Sinatra, and Highland to Brooks 230 kV transmission lines. (Id. at 2-3.)

SNWA Position

266. SNWA witness, Dennis Peseau generally supported the Phase III transmission facilities in Clark County. (Exhibit 43 at 6.)

NPC Rebuttal Position

267. Mr. Whalen stated that Staff witness Mr. Maguire makes several statements in his testimony regarding the Sunrise Option that require clarification. There is not conflicting information in the NPC’s Transmission Plan regarding the in-service date for the Sunrise Option. Further, deferral of the Sunrise Option beyond 2011 would require NPC to purchase the output of the Mirant and Bighorn IPP plants. Because of the critical nature of this facility and the extensive,
complex construction required to construct this project, NPC’s Transmission Planning chose the earliest date identified in the plan, which is 2010. (Exhibit 69 at 2.)

268. Mr. Whalen further explained that the Sunrise Option can be delayed to 2013 if the maximum generation case conditions are met and NPC purchases the output of all the IPP generation within the Las Vegas Valley. He provided NPC’s response to Staff Data Request 209 in support of his position. NPC’s position is that it would be imprudent to attempt to negotiate for the output from these IPPs without first developing another service option, and the Sunrise Option is the only other option of this magnitude and timeframe. (Id. at 2-3.)

269. Mr. Whalen stated that NPC will re-evaluate the timing of the Sunrise Option if it obtains Purchased Power Agreements for the output of the Mirant and Bighorn Plants. (Id. at 3.) Given that NPC intends to issue quarterly RFPs for purchased power agreements with terms of up to five years in accordance with the purchased power procurement strategy in its Energy Supply Plan, it could use the RFP process to make an assessment now regarding whether or not there is IPP capacity within its control area available for the 2010 time frame. Additionally, NPC could complete this assessment without foregoing its ability to construct the Sunrise Option if this capacity is not available. (Tr. at 962-963.)

270. In response to clarification questions regarding the transmission service request submitted by WPEA, Mr. Whalen stated that WPEA has requested 1200 MW of transmission capacity from the Harry Allen 500 kV bus to the Mead 230 kV bus. NPC would likely satisfy this transmission service request by constructing a line that would be adjacent to the existing Harry Allen to Mead line. Mr. Whalen indicated that he was not sure what limitations are placed on NPC as far as how many transmission lines can be run through the Sunrise Instant Study Area. The authorizing legislation specifies two transmission lines but whether this means two sets of towers or two sets of conductors, or other options is a legal question. The transmission service requested by WPEA might well preclude NPC’s last chance to expand the transmission capacity through the Sunrise Instant Study Area. (Tr. at 959-961.) In response to clarification questions regarding NPC’s request to initiate studies, permitting, and land acquisition for Sunrise to Highland, Highland to Sinatra, and Highland to Brooks 230 kV transmission lines, Mr. Whalen explained that the scope of
work for this study would not be completed by NPC personnel but would be contracted to a routing and siting group in a manner similar to what was done with the EVAMP project. (Tr. at 966.)

Commission Discussion and Findings

271. NPC has stated that the transmission projects listed below are needed to reliably serve load growth in various areas within the Las Vegas Valley. Staff concurred with NPC’s position. SNWA provided general support for these transmission projects. The remaining Parties supported or did not oppose these transmission projects:

a) The second Northwest 500/230 kV transformer (three-year Action Plan expenditure amounts totaling $28.5 million);

b) The VARS project (three-year Action Plan expenditures totaling $170.8 million);

c) The Southeast No. 1 230/138 kV substation and the West Henderson 230/12 kV substation components of the West Henderson Improvement projects (three-year Action Plan expenditures totaling $37.1 million; $100,000 in 2007 dollar for permitting activities associated with the Southeast No. 2 230/12 kV substation);

d) The transmission upgrades necessary to support the installation of the new Clark Station CTs, the transmission upgrades at the Arden substation, the transmission upgrades at the McDonald substation, and the transmission upgrades needed for the VEA interconnection (three-year Action Plan expenditures totaling $24.4 million);

e) The Clark 230/138 kV bank No. 6 transformer change out (three-year Action Plan expenditures totaling $200,000 – the total estimated cost of this project is $4.1 million);

f) Expenses to initiate studies, permitting and land acquisition for Sunrise to Highland, Highland to Sinatra, and Highland to Brooks 230 kV transmission lines (three-year Action Plan expenditures totaling $1 million);

272. The Commission is convinced that the transmission projects listed above are needed to reliably serve load growth in the Las Vegas Valley. Therefore, the Commission approves these projects and the expenses for each of these projects as listed above.

273. The Commission finds that NPC has not supported its request to construct the Sunrise Option by 2010. NPC does appear to have time to assess the availability of capacity from
IPPs and complete further economic analysis regarding the timing of the Sunrise Option without foregoing its ability to construct the project.

274. The Commission believes that the Sunrise Option will likely be needed at some point in the near future to support power transfers from the EEC or other resources into NPC’s service territory. However, there is still uncertainty as to when it will be needed and it is clear that premature construction of this project will have a negative impact on rates. NPC should complete a more thorough economic analysis of its options before proceeding to construct the Sunrise Option. Therefore, given the need for the project but the uncertainty of the timing, the Commission finds that the Sunrise Option of the EVAMP project is approved but that NPC is required to submit an amendment before the timing and construction costs are approved. The amendment should include the following two items:

a) The results of an RFP for multi-year products of up to 5 years duration as described in NPC’s ESP that includes additional information regarding NPC’s solicitation of and availability of IPP capacity in the 2010 time frame; and

b) Economic support for the timing of construction of the Sunrise Option. The economic analysis should reflect the need for construction of the Sunrise Option based upon the results of the RFP for long-term resource in 2010-2011, and other analyses that reflects NPC’s use of its own, as well as other resources.

275. With regard to the Equestrian Option of the EVAMP Project, Staff indicated that this Option is not scheduled to be in-service until 2014 and no expenditures for this project are listed in the three-year Action Plan budget in NPC’s IRP application. The Commission notes that the Equestrian Option is presented by NPC as the next transmission project after completion of the Sunrise Option. NPC did not provide a compelling reason for its request for approval of this project at this time. Accordingly, the Commission finds that NPC’s request for approval of the Equestrian Option of the EVAMP Project is not approved.

276. The Commission finds that no party disputes that the construction of the Sinatra substation and that the Sinatra substation is needed to serve transmission customers on the Las Vegas Strip. In addition, Docket No. 06-06007 has been opened to determine an appropriate cost
allocation for the construction expenses for the Sinatra substation. Thus, this issue need not be addressed in this proceeding. Therefore, the Commission approves the construction of the Sinatra substation at a cost of $109.3 million but does not make a finding with respect to the allocation of costs of the Sinatra substation.

277. With regard to construction of the Southeast No. 2 230/12 kV substation, Staff stated that NPC has not listed any expenditures for this project in the three-year Action Plan budget except for $100,000 in 2007 for initial siting and permitting activities. NPC did not provide a compelling reason for Commission approval of this project in this IRP case. Therefore, the Commission finds that NPC’s request for approval of the Southeast No. 2 230/12 kV substation is denied with the exception of approval of $100,000 for initial siting and permitting activities.

278. With regard to WPEA’s request for transmission service agreement (“TSA”) between the Harry Allen 500 kV bus and the Mead 230 bus, the Commission is concerned that the preclusion of NPC’s ability to expand its transmission infrastructure in the Sunrise Instant Study Area may compromise its ability to provide reliable service to the Las Vegas Valley in the future. Hence, the Commission directs NPC to keep the Commission, Staff, and BCP informed of the status of WPEA’s TSA, including any filing before FERC. The Commission also directs NPC to determine its rights for additional transmission projects within the Sunrise Instant Study Area and determine how best to optimize the use of this corridor. This information should be directed to the Commission’s General Counsel, Staff, and BCP when it is available. The Commission also urges NPC and WPEA to explore other transmission alternatives that are not likely to compromise reliability to the Las Vegas Valley.

279. The Commission finds that NPC’s request for approval of expenditures for WestConnect participation and for regional planning studies is approved for the reasons listed above by Mr. Whalen and Mr. Maguire. Therefore, the Commission approves: 1) NPC’s request for expenditures for participation in WestConnect for $166,000 through the Action Plan period; and 2) NPC’s request to expend $350,000 for regional transmission studies to evaluate the feasibility of the Frontier Line and other proposed projects.
E. Demand-Side Management

NPC Position

280. Lawrence Holmes, Manager Customer Programs and Strategy for NPC and SPPC, testified in support of NPC's DSM plan. NPC requested approval of its DSM plan and the expenditure of $31.9 million, $37.4 million, and $36.3 million for calendar years 2007, 2008, and 2009, respectively, for new and existing programs. (Exhibit 103 at 3-4.) The DSM plan reflected NPC's strategy to meet 25 percent of its RPS requirement through DSM programs, as allowed by Assembly Bill 3 ("A.B. 3"), passed during the 22nd Special Session of the Nevada Legislature. The DSM plan also reflected NPC's objective of mitigating peak demand growth by allocating approximately sixty percent (60%) of the 2007 budget to programs such as the Air Conditioner Load Management ("ACLM") and Sure Bet Commercial Incentives which have proven to be effective over the past several years to reduce system peak demand. In general, the largest budget allocations are to those projects with the largest kilowatt reduction potential per dollar (and lowest cost per kW). With the exception of the low-income programs, these programs all have Total Resource Cost ("TRC") ratios greater than 1, indicating that each is cost-effective. NPC opined that the NPC's DSM plan was a well-balanced set of DSM projects that carefully balanced market and performance risk and promises to deliver net benefits of $76 million measured under the Total Resource Cost test (TRC) with a benefit-cost ratio of 1.73. The program tables below can be found in Exhibit 1, Volume V. (Exhibit 1, Volume V at 13-16.)

<table>
<thead>
<tr>
<th>Program Name</th>
<th>Program Description</th>
<th>Proposed 2007</th>
<th>Proposed 2008</th>
<th>Proposed 2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy Star Manufactured Homes</td>
<td>This program will provide incentives to manufacturers, dealers, and contractors to install energy star qualified building envelope measures, air distribution systems, air conditioners and CFLs</td>
<td>$350,000</td>
<td>$358,000</td>
<td>$411,000</td>
</tr>
<tr>
<td>Zero Energy Homes</td>
<td>A pilot program to support the introduction of zero and near zero energy homes in the Las Vegas new home construction market.</td>
<td>$100,000</td>
<td>$330,000</td>
<td>$270,000</td>
</tr>
<tr>
<td>Program Name</td>
<td>Program Description</td>
<td>Proposed 2007</td>
<td>Proposed 2008</td>
<td>Proposed 2009</td>
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</tr>
<tr>
<td>Energy-Efficient Pool Pumps</td>
<td>This program will provide incentives to residential customers to install energy efficient two-speed pool pumps</td>
<td>$814,000</td>
<td>$898,000</td>
<td>$1,033,000</td>
</tr>
<tr>
<td>Cool Controls Plus Project</td>
<td>This program will assist small hotel and motel owners install air conditioner controls and occupancy sensors</td>
<td>$1,180,000</td>
<td>$1,340,000</td>
<td>$0</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td>$2,444,000</td>
<td>$2,926,000</td>
<td>$1,714,000</td>
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<tr>
<td><strong>Existing Programs—Expanded</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Star Lighting and Appliances</td>
<td>This program provides direct incentives to customers who purchase program-specified energy star appliances and lighting products</td>
<td>$3,100,000</td>
<td>$3,100,000</td>
<td>$3,100,000</td>
</tr>
<tr>
<td>Residential ACLM</td>
<td>This program provides bill credits to residential customers who agree to permit NPC to install a control device on their air conditions which can control the operation of the system during peak periods</td>
<td>$7,938,000</td>
<td>$11,811,000</td>
<td>$13,133,000</td>
</tr>
<tr>
<td>Sure Bet Commercial Incentives</td>
<td>The Sure Bet Commercial Customer Incentives Program provides incentives to commercial, industrial and institutional customers to install energy saving devices such as lighting, cooling, motors, refrigeration and vending machine controls. In addition, incentives are offered for any measure not included in the prescriptive measure.</td>
<td>$6,000,000</td>
<td>$6,000,000</td>
<td>$6,000,000</td>
</tr>
<tr>
<td>Sure Bet New Construction</td>
<td>Targets new commercial construction</td>
<td>$1,600,000</td>
<td>$1,600,000</td>
<td>$1,600,000</td>
</tr>
<tr>
<td>Second Refrigerator Collection and Recycling Project</td>
<td>The Second Refrigerator Collection and Recycling Project is designed to help customers reduce their energy consumption by removing second refrigerators from their homes and to recycle these units through a process which safely dispose of environmentally harmful material.</td>
<td>$1,650,000</td>
<td>$1,650,000</td>
<td>$1,650,000</td>
</tr>
<tr>
<td>Low Income Projects</td>
<td>Targets low-income dwellings for weatherization services</td>
<td>$2,200,000</td>
<td>$3,380,000</td>
<td>$3,380,000</td>
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</tbody>
</table>
**Existing Programs—No Change**

<table>
<thead>
<tr>
<th>Program Name</th>
<th>Program Description</th>
<th>Proposed 2007</th>
<th>Proposed 2008</th>
<th>Proposed 2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sure Bet Schools</td>
<td>This project facilitates conservation and peak demand reduction in public schools.</td>
<td>$400,000</td>
<td>$400,000</td>
<td>$400,000</td>
</tr>
<tr>
<td>Non-Profit Grants</td>
<td>This program provides grants for general efficiency upgrades to commercial spaces leased or owned by non-profit organizations</td>
<td>$100,000</td>
<td>$100,000</td>
<td>$100,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$500,000</strong></td>
<td><strong>$500,000</strong></td>
<td><strong>$500,000</strong></td>
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</tbody>
</table>

**Existing Projects—Declining Budgets**

<table>
<thead>
<tr>
<th>Program Name</th>
<th>Program Description</th>
<th>Proposed 2007</th>
<th>Proposed 2008</th>
<th>Proposed 2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential High Efficiency AC Rebate</td>
<td>This program provides rebates to home builder and homeowners who install program-specified high-efficiency air conditioners.</td>
<td>$5,545,000</td>
<td>$5,485,000</td>
<td>$5,428,000</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>$5,545,000</strong></td>
<td><strong>$5,485,000</strong></td>
<td><strong>$5,428,000</strong></td>
</tr>
</tbody>
</table>

**NCARE Position**

281. Howard Geller, Director of the Southwest Energy Efficiency Project, testified on NPC’s proposed DSM plan. NCARE proposed a total budget of $140.53 for the three-year period of 2007-2009. This is approximately $35 million more than the $105.12 million requested by NPC. (Exhibit 110 at 32.) The additional budgets would be used to expand the Energy Star Appliance Program, Sure Bet Commercial New Construction Program, Sure Bet Schools Program, Residential Air Conditioning programs, and accelerate the implementation of the Zero Energy Homes program. (Id. at 13-14, 16-17.)
282. Dr. Geller indicated that the proposed reductions to the residential air conditioning program should be looked at closely. This program was cost-effective with an estimated TRC value of 2.16. Most of the impacts were expected in the new construction market; relatively low participation rates (2,250 units per year) are assumed in the replacement market. This was a small fraction of the total number of central AC units replaced each year in the Las Vegas area. (Id. at 14.)

283. Dr. Geller further explained that the quality installation component of the program was only offered in the new construction market according to the project data sheet. NCARE recommended expanding the program to capture a greater portion of the replacement market which should be feasible given that the Company is building up its relationship with HVAC contractors and that the availability of high efficiency products was expected to grow over time. Extending the quality installation component to the replacement market is another way to expand the program and increase energy savings. This is desirable given that the energy savings per rebate dollar is greater for the quality installation portion of the program relative to the high efficiency equipment portion. (Id. at 14.)

**BCP Position**

284. Tim Woolf, Vice President, Synapse Energy, testified on behalf on the BCP. The DSM programs in the DSM plan were generally well designed and were likely to be cost-effective. The Company has done a good job of ramping up and expanding its DSM programs in order to contribute to its efforts to comply with A.B. 3. (Exhibit 111 at 3.)

285. Mr. Woolf recommended that the Commission approve the budget levels included in the Demand Side Plan for years 2007, 2008 and 2009; however, BCP recommended that this approval be conditioned on the Company making certain changes to the DSM plan. (Id. at 3.)

286. Mr. Woolf proposed several changes to NPC's Nonprofit Agency Grants program. First, NPC should consider increasing the $5,000 cap. Second, it should consider increasing the $15,000 cap for grant money that must be matched by other funds. Further, BCP recommended that the total budget be increased to a level that ensured no customers are turned away. (Id. at 22-23.)

287. With respect to the Low-Income Program, Mr. Woolf noted that this program was not cost-effective but should be approved since it promoted equity across customer types with
regard to DSM program participation. BCP stated that it was very supportive of the proposed new Outsourced Weatherization component because it would enable the Company to reach a significantly greater number of needy customers, and it will provide an important demonstration of alternative implementation and delivery options. BCP recommended that the Commission approve this program and approve the Company's budget request for this program. (Id. at 23.)

Staff Position

288. Staff witness, Jeffrey Pasquinelli, recommended that the Commission adopt certain changes to the NPC's DSM plan. These changes fell into four general categories: 1) program consolidation and reduction budgets; 2) program approvals with lower budgets; 3) program rejections; and 4) program approvals. Staff proposed that the Commission adopt budgets of $21,620,633, $25,658,500 and $26,269,500 for 2007, 2008 and 2009, respectively. (Exhibit 112 at 1-3.)

289. Mr. Pasquinelli recommended that NPC consolidate a number of its existing and new programs. Staff made these recommendations on the basis of reduced administration costs and greater efficiencies. (Exhibit 112 at 7-8 and 18-19.)

290. Mr. Pasquinelli recommended the Commission approve the following programs: Low-Income Program, Second Refrigerator Recycling program, Energy Star lighting and appliances program, the Sure Bet new construction program, the Energy Star manufactured homes program, and the Non-Profit Agency Grants program. (Exhibit 112 at 2, 10-11, 14-16.)

291. Mr. Pasquinelli recommended the Commission approve the Sure Bet New Construction program, but at levels lower than those proposed by NPC due to potentially high levels of freeridership and diminishing returns. Staff proposed funding levels of $900,000 each year, for 2007-2009, reasoning that while the number of participants in this program could increase five-fold over this 3-year period from the 2005 levels, this does not mean that the budget will also increase by 5.5 times. (Exhibit 112 at 17-18.)

292. Mr. Pasquinelli recommended the Commission reject the Zero Energy Homes, Energy Education and Consultation, and Technology Trials programs because they did not meet the standards provided in NAC 704.934. (Exhibit 112 at 8-9, 11-14.)
NPC Rebuttal Position

293. In response to Staff’s recommendation, NPC’s witness, Lawrence Holmes, noted that
the Zero Energy Homes project is a pilot project, and due to the uncertainty of the savings value
within the range presented, no savings were included in the overall expected savings in the Action
Plan. However, NPC did prepare a range of savings that were included in NPC’s DSM Plan at A-
135. Because energy savings have been projected for this project, there is no basis to support
Staff’s recommendations that this program be rejected. (Exhibit 113 at 6-7.)

294. Mr. Holmes explained that with respect to the Cool Controls Program, Staff reasoned
that small hotel and motel owners in many cases will make the expenditures necessary to improve
energy efficiency without the incentives proposed by NPC. Staff provided no data to support its
argument. Further, NPC’s market research indicated that the opposite was true. (Exhibit 113 at 9-
10.)

295. Mr. Holmes observed that Staff presented no data to support its assertion that
funding the Sure Bet Commercial Incentive project at the levels requested by NPC will result in
diminishing returns. In addition, Staff provided no supporting evidence that an increased funding
level on this project will increase the level of free riders. The facts indicate quite the contrary. The
initial funding in this project for 2006 was fully committed within the first quarter of the year, and a
waiting list with projects in excess of $1 million was created within two months. A lower level of
funding, and a lower level of incentives, as recommended by Staff, would in fact result in a higher
level of free riders. A market evaluation based upon experience in other markets indicated that the
NPC market can cost effectively absorb this project at the requested funding level. (Exhibit 113 at 7.)

296. Mr. Holmes stated that in terms of the day-to-day operations of these programs, NPC
will hire an implementation contractor who will be managed by an internal project manager who is
supervised by a manager. It is possible that there will be multiple contractors involved in multiple
programs or a single contractor involved with multiple programs. One contractor has multiple
programs and was invited by NPC to include these efficiencies into its competitive bid. This may
not be possible for all programs. (Tr. at 1597-1601.) For example, Staff recommended that the air-
conditioner rebate and pool pump rebate programs be combined. This was not practical since these programs targeted two completely different markets. (Exhibit 113 at 21.)

297. Mr. Holmes responded to the Commission's concerns regarding the Second Refrigerator Recycling program expressed in Docket Nos. 06-03038 and 06-04018 by implementing a revised measurement and verification ("M&V") process that provides audit and verification results. The new process implemented by NPC added one key additional step. The refrigerator is disfigured beyond further use as a hole is punched in the door at the time it is picked up from the customer's residence, but it is left such that the cooling system can still be operated. The additional check added by NPC occurs at the contractor's collection point. In this new process a random selection of refrigerators constituting a representative sample is selected by an NPC representative or NPC's M&V contractor. These units are then plugged in to demonstrate that they are in fact operative units. This revised process was designed to specifically address the Commissions concerns regarding adequacy of the quality control process in this project. (Exhibit 113 at 11-12.)

298. Mr. Holmes noted that in NPC's Integrated Resource Plan filed in 2003, the 2004-2006 DSM Plan had a Low Income project that was 7.7 percent of the total budget (not including the budget increases for 2006 made in Commission Docket No. 06-03038). For the 2007-2009 DSM Plan, the proposed Low Income budget is 8.5 percent of the proposed DSM Plan Budget. NPC has proposed increases to the Low Income project in order to achieve a reasonable parity between the Low Income budget and the overall DSM budget. (Exhibit 113 at 11.)

Commission Discussion and Findings

299. The Commission finds that NPC’s proposals are in the public interest, and utilizing the TRC, all programs except the low income programs, are cost-effective. Further, the Commission finds that NPC’s proposed DSM budgets for 2007, 2008, and 2009 are necessary for NPC to achieve its stated goals with respect to the RPS compliance and peak reduction. Therefore, the Commission approves NPC’s proposed DSM budgets for 2007, 2008, and 2009, with the exception of the requested funds for the Low-Income Air Conditioner Replacement Program for the reasons stated below.
300. With respect to the Low-Income Air Conditioner Replacement Program, the Commission, in its final Order in Docket No. 06-03038, approved this program on a pilot basis only. The record indicates that initial results for this program will first be available in 2007, at which time the Commission will review this program. The Commission therefore approves a budget of $500,000 for 2007 and will consider requests for additional funding after reviewing the results of the pilot.

301. Both NCARE and BCP proposed increases to certain budgets in addition to those proposed by NPC to capture additional cost-effective energy efficiency opportunities. Further expenditures are not in the public interest at this time. The sole exception is the case of the residential high-efficiency air conditioner program. This program's budget will be reduced from its 2006 budgeted level of $14.5 million to approximately $5.5 million in each of the next three years. The Commission agrees with Dr. Geller that additional opportunities may exist given both the size of the air conditioner market in the Las Vegas area and the contribution of air conditioners to peak load. NPC is directed to reassess this program and to consider such innovative approaches such as targeting super-high efficient air conditioners. The Commission directs NPC to file its findings and any proposal at the time it files its 2007 annual DSM Update Report.

302. Staff opined that the consolidation of programs could achieve administrative and cost-efficiencies. However, it is clear from rebuttal testimony that the potential for such savings is very limited. Therefore the Commission finds Staff's proposals should be rejected.

303. With respect to the Technology Trials Program that Staff recommended be rejected, the Commission, in Docket No. 05-12001, found that addressing conservation and DSM issues by using a systematic process for evaluating the potential of technologies is necessary in order to develop and implement new programs. Therefore, the Commission approves the Technology Trials Program.

304. With respect to the Outsourced Weatherization portion of the Low Income Project, the Commission supports the Company's effort to reach low income customers whose income is between 150 percent of poverty and 60 percent of the county median income (known as "gap" customers). However, the Commission is concerned with the potential of a duplication of efforts
with the Division of Housing's Weatherization Program. The Commission directs the Company to coordinate with the Division of Housing to ensure that their programs are complementary and reach the maximum level of low income customers.

305. The Commission believes that appropriate incentives for utility DSM programs are necessary. The exact nature and form of incentives that should be offered for such programs include a number of factors, including the regulatory and statutory environment. The current incentives for DSM were implemented in 2001 when the Companies had few, if any, incentives to implement DSM programs. The enactment of A.B. 3 changed both the regulatory and statutory context. Utilities now have incentives to implement DSM to meet portions of their respective renewable portfolio standard requirements. NPC's expenditures will increase almost four-times compared to pre-A.B. 3 during this action plan.

306. Given these changes it is now time to reexamine the mandatory package of incentives provided to DSM programs. This includes the types and categories of costs eligible for expense treatment as well as prescribed incentives. The Commission therefore directs the Commission's Secretary to open an investigation and rulemaking into the appropriateness of DSM cost recovery mechanisms and incentives.

**Programs Not Adopted by NPC**

**NPC Position**

307. The DSM planning process involved the review and consideration of NPC's existing programs as well as twenty-two new program concepts. Of these twenty-two new program concepts, NPC proposed to implement four new programs. Those considered and not adopted include the residential A/C maintenance program, Energy Star Plus new homes, efficient office equipment, and the residential products incentive program. (Exhibit 1, Volume V at 14-16.)

**NCARE's Position**

308. NCARE witness, Howard Geller, identified several programs that were not recommended for implementation by NPC that it wanted reevaluated. This list included the residential products incentive program, residential A/C maintenance program, Energy Star new homes and the high-efficiency office equipment program designed to promote greater energy
efficiency in desktop and laptop computers. He recommended that NPC continue to examine these programs and consider their implementation in the future. (Exhibit 110 at 21-22; Tr. at 1483.)

NPC Rebuttal Position

309. NPC witness, Lawrence Holmes, responded that many of the programs not recommended for adoption were not rejected outright by NPC. Rather, additional analytic work was needed before these programs could be brought forward to the Commission. In particular, the uncertainty regarding the new Energy Star standards has slowed the development of a new home construction program. NPC stated that it was open to all programs in the future. (Tr. at 1547.)

Commission Discussion and Findings

310. The Commission is satisfied that the portfolio of DSM programs proposed by NPC are well-suited to meet the load objectives and public policy objectives identified by NPC. The Commission finds that NPC's DSM Plan adequately reflects NPC's strategy to meet 25 percent of its RPS requirement through DSM programs, as allowed by A.B. 3, and mitigates peak demand growth by utilizing programs that have proven to be effective over the past several years to reduce system peak demand. However, the Commission believes that NPC should continue to analyze new and innovative programs, such as the Energy Star Plus Homes program and the high-efficiency office equipment program. The Commission directs NPC to reevaluate these programs and include the results as part of NPC's annual DSM Update Report to be filed in August 2007.

F. Renewable Energy

NPC Position

311. Thomas R. Fair, Executive for Renewable Energy for NPC and SPPC, testified in support of the RPS and supply, and the request for approval of expenditures that support the planning and development of new renewable energy resources. NPC expects to expend an additional $2 billion over its current expenditures for renewable energy to attain RPS compliance between 2007 and 2015. (Exhibit 3 at 3-4.) This estimate did not include the costs of demand-side management programs that would count towards RPS compliance. (Tr. at 53.)

312. Mr. Fair stated that NPC has developed a three-pronged approach for meeting the RPS requirement: 1) long-term power purchase agreements; 2) equity investments in renewable
facilities; and 3) DSM activities. (Tr. at 48.) NPC requested Commission approval of a Renewable Energy Action Plan Budget of $18.45 million. This consists of expected expenditures of $6.2 million in year 2007, $6.25 million in year 2008, and $6.0 million in year 2009 to execute this plan. (Exhibit 3 at 8-9.)

313. Mr. Fair stated that, with respect to long-term purchased power agreements, NPC requested Commission approval to use annual RFPs to fulfill the RPS, and to bring all contracts executed pursuant to such RFPs forward for Commission approval. (Exhibit 3 at 7.) In response to criticism regarding previous RFP solicitations, the Companies conducted an assessment of renewable energy procurement practices by utilities in the west with the objective of streamlining and shortening the process. (Tr. at 49.) NPC is reviewing and amending its procedures to improve the process of entering into long-term power purchase agreements. The improvements would, among other things, improve the project success rate by shortening the time needed to complete the proposal and contract processes and to better identify developers with the necessary qualifications to complete projects prior to issuing the RFP. (Exhibit 1, Volume VI at 69-70.)

314. NPC requested $17.5 million for the formation of a new renewable energy department. The three-year Action Plan Budget for renewable energy development also includes consulting and legal expenses, and labor costs associated with this effort such as resource assessment, technical and legal due diligence, siting and conceptual engineering studies, land acquisition, budget preparation, and financial analyses. These development costs will be incurred prior to NPC bringing forward a request for Commission approval of specific renewable energy generating projects. (Exhibit 1, Volume VI at 71.) Mr. Fair stated that the activities were necessary to undertake the evaluation of a number of possible projects and bring forward a number of solid projects for Commission approval at a later date. (Tr. at 47.)

315. NPC requested that the Commission approve expenditures of $400,000 in 2007 and an additional $410,000 in 2008 for on-site wind resource measurement equipment at multiple sites. NPC proposes to identify suitable locations in 2006 and to install wind measurement equipment, include 60-meter high and 80-meter high towers equipped with anemometers and related meteorological instruments at several prospective project sites during 2007 and 2008. NPC also
requested approval for the expenditure of $50,000 each year thereafter to maintain the equipment and collect the data. If the measurements, when analyzed, indicate a sufficiently strong wind resource, and other key wind farm siting parameters prove to be favorable, NPC would invest additional funds in further project development, subject to separate approval by the Commission. (Exhibit 1, Volume VI at 76-77.)

316. NPC seeks approval for the expenditure of $200,000 to conduct a wind integration study to determine the impacts of non-firm wind on the electric system. (Exhibit 1, Volume VI at 79.) Mr. Fair explained that the study would be used to determine the extent to which both SPPC and NPC can integrate an intermittent resource into their systems, before and after the tie line is put in place; what the costs might be of doing so; and what mitigation might be needed. NPC is in the process of evaluating consultants with substantial experience analyzing wind integration in other states. The Nevada Wind Integration Reliability Study should be completed by mid-2007. (Tr. at 56.)

317. Mr. Fair outlined the expected schedule for wind development. NPC had identified eight potential wind sites and was currently doing wind modeling and other exploratory work at these sites. If six of these projects went to the next step in the development process a total of 400-600 MW of wind capacity. Mr. Fair indicated that some of these projects may not ultimately be developed after due diligence and research is completed. NPC expected to come forward with the most mature of these projects for Commission approval during the first quarter of 2007 with a project for NPC. (Tr. at 38-39.) Mr. Fair stated that there could be several hundred megawatts installed on the NPC and SPPC systems by the end of 2008. (Tr. at 60-62.)

NCARE Position

318. NCARE witness, Ronald Lehr, supported NPC's requests related to renewable energy stating that these requests are necessary to bring specific renewable energy resources forward for approval. (Exhibit 97 at 10.)

BCP Position

319. BCP witness, Dale Stransky, supported NPC's requested approval of $400,000 to conduct detailed wind modeling, but took the position that it is premature to approve $810,000 to
deploy wind measurement equipment prior to the completion of further wind modeling. BCP explained that it supports deploying wind measurement equipment for site-specific data once the wind modeling identified potentially viable wind sites, but rather than endorsing the specific amount requested at this time for wind measurement equipment, BCP concluded that NPC should use its judgment to determine an amount for specific-site wind measurement equipment deployment after seeing the results of the wind modeling. BCP endorsed NPC’s moving ahead with wind measurement without further Commission approval but does not oppose NPC seeking pre-approval of the budget through a resource planning amendment. (Exhibit 79 at 4-5.)

320. Mr. Stransky cited, as support for the wind modeling, NAC 704.948 (integrated decision process including cost mitigation), and NAC 704.9489(1)(f) (identification of plans to acquire additional modeling instruments). In its pre-filed testimony, BCP did not cite to any regulations prohibiting Commission acceptance of wind measurement costs, but presented it as a two-step process of first verifying through modeling whether the second step of specific-site wind measurement should be undertaken. On cross-examination, Mr. Stransky, supported his opposition to NPC by referencing NAC 704.9166, NAC 704.9321(3)(c), and NAC 704.9385(2). (Tr. at 1087-1088.)

321. Mr. Stransky recommended that the Commission not approve $18.5 million ($17.5 million over the three-year action plan) for expenses that are projected to be capitalized to undetermined future renewable energy projects. These costs, including employee salary and non-salary expenses, are not appropriate to be addressed in this docket. BCP took the position that it is inappropriate to include in the IRP proposals for employee salary and consulting costs. Both in pre-filed testimony and on cross-examination, Mr. Stransky opposed the Commission considering and accepting NPC’s request to expend approximately $18 million related to the new renewable energy department. His opposition is based on the Commission regulations cited above, the hope that expenses will be capitalized into future projects, the Commission’s amendment of its regulations in Docket No. 02-5030 (April 2004), and a change of recovery of costs for preparing a resource plan from a balancing account process to the general rate case process. (Tr. at 1092-1096; Exhibit 79 at 6-7.)
Staff Position

322. Mark P. Harris, Staff Resource Planning Engineer, testified that the renewable energy plan was a realistic strategy for NPC to achieve full and complete compliance with the RPS. (Tr. at 1066.)

323. Mr. Harris recommended that the Commission approve the use of annual renewable RFPs to fulfill renewable portfolio short positions for 2007, 2008, and 2009 instead of the sporadic process currently used. Staff noted that an RFP was issued October 2001, and seven contracts were brought to the Commission in November and December 2002. The 2003 RFP was issued in June 2003 and eight contracts were brought to the Commission in November 2004. The 2005 RFP was issued in June 2005 and one contract was brought to the Commission on May 31, 2006. The Companies have stated that an additional five contracts will be brought to the Commission in September 2006.\(^\text{16}\) It took NPC approximately 14, 16, and 12 months for internal negotiations, reviews, and approvals before any resulting contracts were brought to the Commission for approval. Staff noted that NPC had implemented procedures to shorten the time needed to complete the RFP process. (Exhibit 76 at 3-4.)

324. With respect to self-build options, Mr. Harris recommended that the Commission approve spending $400,000 to conduct wind resource modeling in year 2007 of the Action Plan. The Commission should not approve any expenditure in 2006, as it is outside the Action Plan period. Further, the Commission should approve spending $200,000 to conduct a wind integration study in 2007 to determine the impacts of non-firm wind generated electricity on the electric system. The Commission should encourage the continuation of NPC’s membership in the Utility Wind Integration Group ("UWIG") to maximize this effort and possibly reduce the final costs of the wind integration study. Staff further recommended that the Commission approve $810,000 for the installation of wind measurement equipment. The Commission should also approve spending $17,501,000 to conduct pre-development work necessary for NPC to initiate self-built renewable projects in the Action Plan for years 2007, 2008, and 2009. (Exhibit 76 at 4-9.)

\(^{16}\) On October 13, 2006, NPC filed an Application, designated as Docket No. 06-10021, requesting Commission approval for five renewable contracts.
NPC Rebuttal Position

325. With respect to BCP's contention that it is premature to consider costs related to the proposed renewable energy department, NPC stated that for the past six months NPC has made every effort to assure developers that it will be able to make prompt decisions as a development partner and be able to co-fund joint development of promising projects, with the intent of taking projects to the Commission for approval once the economics, performance, construction costs, and schedule are fully defined. Denial of approval of pre-development funding would send a contrary message to developers who are considering joint venture projects with NPC indicating by extension that developers themselves would face financial risk, regulatory intervention in decisions such as where and when to deploy anemometer towers, and consequent delays. (Exhibit 4 at 5-6.)

326. As with all capital projects, pre-development work on projects will be captured in holding accounts, and capitalized as decisions are made to move to full development. (Exhibit 4 at 6.)

Commission Discussion and Findings

327. NPC proposed a three-pronged approach to fulfill its obligations pursuant to the Nevada RPS: 1) reliance on long-term contracts solicited through an annual RFP; 2) the initiation of self-build options; and 3) utility-sponsored DSM programs. No party took exception to the substance of NPC's plan, nor its request to use annual RFPs, the $400,000 for wind-modeling, and the $200,000 for the wind integration study. The Commission recognizes that NPC's three-prong approach is an aggressive one, and the Commission fully supports NPC in these efforts.

328. The Commission acknowledges NPC's efforts with wind development. Wind development in Nevada is an important public interest and the Commission is excited at the prospect of having an NPC wind project completed by the end of 2008.

329. With respect to BCP's opposition to Commission approval of certain expenditures, the Commission's regulations do not prohibit it from granting approval of NPC's Action Plan request to expend approximately $810,000 related to wind measurement equipment and approximately $18 million for a renewable energy department. Those regulations, which contain basic information requirements for existing and proposed projects, do not preclude a request for pre-
project costs. The Commission cannot accept BCP’s interpretation of the regulations. It is
appropriate to consider these requests given the need for substantive progress to meet the aggressive
RPS targets.

330. NPC has struggled in the past 3 years to meet its solar and non-solar RPS
obligations. The Commission notes that the RPS requirement will increase from the current level of
6 percent of retail sales to 9 percent of retail sales in 2007 and will increase every second year until
reaching 20 percent by 2015. NPC expects it will have to expend an additional $2 billion over
current expenditures through 2015 to attain compliance. The Commission believes that the $18.5
million Renewable Energy 3-Year action plan budget, the $400,000 for wind-modeling, the
$200,000 for the wind integration study and the $810,000 for NPC to conduct wind measurement
studies, are part of a realistic strategy to assist NPC to meet its statutory obligations. Therefore, the
Commission approves these requests.

Natural Gas Pressure Letdown Study

NPC Position

331. John Lescenski, Manager of Generation Asset Performance Management for the
Companies, sponsored a report, prepared by the Washington Group International, of the feasibility
of using pressure letdown generator assemblies at various locations in NPC’s service territory.
(Exhibit 25 at 3-4.) This study evaluated the feasibility of utilizing pressure letdown generator
assemblies at the following five locations in NPC’s service territory: Lenzie Plant, Silverhawk
Plant, Centennial Tap City Gate, Blue Diamond City Gate, and the Original City Gate. Letdown
generator assemblies would utilize energy that is being lost through a control valves reduction in
natural gas pressure. A letdown generator system may be capable of extracting energy and
converting it to electricity. The letdown generator would be installed parallel to the existing
control/regulating station to permit operation through either flow path. (Exhibit 1, Appendix II-1 at
419-420.)

332. Mr. Lescenski stated that the base evaluation (Lenzie Plant conditions) indicated that
an expansion turbine system with additional gas preheating could produce approximately 4 MWs.
A more complex combined-cycle expansion turbine system, which utilizes a small gas turbine to
provide the gas preheating, could produce approximately 10.5 MWs, according to the vendor’s claim (no more than 8 MWs based on a thermodynamic prediction model check). The study found that the combined cycle system is not practical and there are significant issues that need to be considered, such as a new emission source that will need to be permitted. Further, the dynamic stability of the letdown generator system has the potential to impact both the reliability and availability of the power plant operation and transients within the power plant equipment have the potential to impact the letdown generator. While these impacts cannot be completely quantified without performance of a detailed dynamic analysis of the systems, they do suggest a risk to the stable operation of the power plant equipment and systems. These risks to the generating assets within the NPC system are potentially significant and would require substantial additional analysis to confirm or refute the legitimacy of such risks. (Exhibit 1, Appendix II-1 at 420.)

**BCP Position**

333. BCP witness, Dale Stransky, recommended that the Commission order NPC to continue its evaluation of renewable resources from natural gas pressure letdown-generation applications. (Exhibit 79 at 7.)

334. Mr. Stransky concurred with the results of the study showing that the Centennial and Blue Diamond Tap locations are feasible sites for natural gas letdown-generation applications, and that further evaluation of this potential renewable resource application near the Lenzie and Silverhawk Plants was warranted. (Exhibit 79 at 8.)

**Staff Position**

335. Staff witness, Jon Davis, testified that a gas step-down facility was similar to an in-line turbine. Staff indicated that this device would be placed front of an 1100 megawatt or a 500 megawatt facility. Staff cautioned the Commission about potential reliability considerations at combined cycle plant, observing that the 5 megawatts capacity related to a gas letdown system could jeopardize the operation of a large gas plant and reliability if letdown system were to fail. (Tr. at 1156-57.)
NPC Rebuttal Position

336. NPC witness, John Lescensi, stated that the technical issues raised to operating this technology at an NPC plant have not been resolved. These issues relate directly to the operational reliability of these important facilities. There are no other power plants in the US deploying this technology. (Exhibit 89 at 2.) Given the small potential capacity gains of 10 MW at 1200 MW coupled with the reliability and operational concerns, the Company and its consultants have decided to not pursue this technology at this time at its generating stations. (Tr. at 1175.)

337. Mr. Lescensi noted that, following the completion of the Study, the Centennial and Blue Diamond Taps were further considered on qualitative available information and normal industry practice for systems of this type. The reconsideration identified economics to control the temperature at the tap, which could require refrigeration, or if free waste heat is available in the vicinity of the gas expansion. Neither of these criteria will be met at the Centennial or Blue Diamond taps. Also, downstream users of the Centennial and Blue Diamond taps include critical power generation facilities: Clark Station and Las Vegas Cogeneration. If these are the primary users downstream of the taps, then there is substantial risk to electrical upsets if the turbo-expanders trip and parallel pressure reduction devices cannot pickup the load quickly enough. Further, there is no transmission or distribution readily available in the vicinity of the taps in question. Finally, pursuing such a system is not something NPC could do unilaterally. It would require the cooperation of Kern River Gas Transmission Company, which is the entity that owns and operates the pipeline system and gates. (Exhibit 89 at 3-5.)

Commission Discussion and Findings

338. The Commission is supportive of innovative technologies but recognizes the Companies' and Staff's concerns for reliability. The Commission recognizes that there has been no successful commercial utility application of gas pressure letdown generation technology in the United States. Therefore, there is no evidence to support that this technology is suitable for NPC at this time.
G. End of Economic Life for Generation Equipment

NPC Position

339. NPC witness, Gary McDonald, sponsored NPC’s request for approval of the retirement dates for generation equipment listed in its 2007-2026 IRP. NPC is requesting approval of the retirement dates in Figure SS-1 in its Application to enable it to use them with confidence when it calculates depreciation rates. (Exhibit 72 at 2.)

340. Mr. McDonald stated that for many reasons generation assets often either fall short of or out-live their original estimated useful lives. This is due to many factors, one of which is the manner in which the generator is operated over time. Therefore, it is appropriate for NPC to update generator retirement dates during the IRP process, and by using the retirement date information from IRPs to determine depreciation rates, the investments are more likely to be recovered over appropriate time frames. (Id. at 3-4.)

Staff Position

341. Staff witness, Paul Maguire, recommended that the Commission reject the “end of economic life” dates proposed by NPC, approve the retirement dates presented in Attachment PRM-2 and order NPC to use those dates in any future depreciation study filings. (Exhibit 74 at 5.)

342. For various reasons, Mr. Maguire objected to the retirement dates proposed by NPC for Reid Gardner Units 1-3, the Silverhawk and Lenzie Plants, and Harry Allen Units 3 and 4. The retirement dates that NPC listed for the units other than those mentioned above are reasonable. (Id. at 6-13.)

343. In response to clarification questions regarding the appropriateness of addressing retirement dates in an IRP, Mr. Maguire stated that the IRP is an appropriate place to consider the impact on equipment lives associated with political and regulatory factors. (Tr. at 1638.)

344. In response to clarification questions regarding whether a retirement date for a generating unit could be addressed in an amendment to an IRP instead of an IRP, Mr. Maguire stated that for situations where new data presented in an amendment is relevant to the establishment
of the retirement life of a generating unit, this information could be used in a depreciation case that follows that amendment. (Tr. at 1638.)

**BCP Position**

345. BCP witness, Jacob Pous, Principal in the firm of Diversified Utility Consultants, Inc., provided testimony addressing NPC’s request that the Commission approve the retirement dates listed in its Application for its generation equipment. (Exhibit 81 at 4.)

346. Mr. Pous disagreed with NPC’s proposed retirement dates. NPC did not substantiate its proposed retirement dates for many of its generating units by any valid study or analyses and, when asked for such analyses, was unable to provide this information. He added that, as a result, NPC has no support for the retirement dates listed in its Application. (Id. at 14.) In addition, he stated that NPC’s proposed dates are inconsistent with dates used by its own depreciation consultant in recent depreciation studies. (Id. at 10-11.)

347. Mr. Pous provided recommended retirement dates based on information he was able to identify that could be used to test the validity of NPC’s proposed retirement dates. (Id. at 10-14.)

348. Mr. Pous stated that with respect to the retirement dates for NPC’s generating units, he recommended that whatever decision the Commission makes regarding the retirement dates for the units in this docket should not prohibit the parties in NPC’s upcoming general rate case from further evaluating and investigating reasonable life spans for NPC’s generating facilities. (Id. at 14.) This request was attributed to the possibility of changed circumstances due to the time span between when the IRP is addressed by the Commission and a general rate case is filed. He also noted that one normally does not find interveners in an IRP process that are looking at the depreciation issue as is being done by NPC in this proceeding. (Tr. at 1145.) In response to clarification questions regarding why this Commission is addressing retirement dates in this proceeding, Mr. Pous stated that he thought it was the goal of the Commission to get the best retirement date possible. (Id. at 1145.)
NPC Rebuttal Position

349. NPC witness, Gary McDonald, rebutted portions of Mr. Maguire’s and Mr. Pous’ testimony regarding retirement lives of NPC’s generation equipment. (Exhibit 88 at 1.)

350. Mr. McDonald provided the following recommendations regarding their rebuttal testimony:

a) The Commission should accept the recommendation of Mr. Maguire to revise the retirement dates for Reid Gardner Units 1, 2, and 3 to 2012;

b) The Commission should accept Mr. Maguire’s recommendation to use a 35-year life for the Lenzie and Silverhawk Plants and not accept Mr. Pous’ recommended 44-year life;

c) The Commission should accept the modification proposed by Mr. Maguire to increase the life of Harry Allen Units 3 and 4 from 25 years to 30 years;

d) The Commission should accept Mr. Maguire’s recommended retirement dates as outlined on Attachment PRM-2;

e) The Commission should not accept the recommendations of Mr. Pous to establish a 50-year life for steam turbines and a 35-year life for CTs. (Id. at 2.)

Commission Discussion and Findings

351. The Commission believes that, in general, all parties in this proceeding have indicated that the primary goal for determining the appropriate retirement dates for generation equipment is to allow the utility to recover the generating unit’s cost ratably over the period of time that it provides service or benefit to NPC’s customers with the hope that the cost of the asset will be recovered by the time the asset is retired. The Commission endorses this goal.

352. The Commission further believes that there is confusion among the parties regarding how the IRP process is to be used for selecting retirement dates and addressing other input data for use in a depreciation case. The Commission has ordered in previous dockets that retirement dates established for specific units in an IRP should be used in a depreciation study,¹⁷ and that the IRP is

¹⁷ Docket No. 01-11031, Order at 99, paragraph 367, issued December 17, 2002;
the best context for the review of certain input data for a depreciation case.\(^\text{18}\) The Commission affirms its position in those previous orders. The IRP process is an appropriate place to consider certain factors that affect retirement dates or depreciation rates. These factors, as clarified by this record, can include political, environmental, end-of-life assessment (e.g., remaining life studies), decommissioning costs, and other factors that affect the depreciation expense for a generating unit.

353. Consistent with the Commission’s goal as stated above, the best available data for determining depreciation rates is to be used for calculating depreciation rates. Accordingly, the utilities should use the best available information that originates from an IRP, amendment to an IRP, or a depreciation study for developing depreciation rates.

354. The Commission believes that the process for determining how to use the IRP proceeding to determine certain input data to be used in establishing depreciation rates is still developing. Further, in this proceeding a full analysis to determine the appropriate retirement dates for NPC’s generating units has not been completed. Therefore, the Commission finds that the retirement dates proposed by NPC and the other parties in this proceeding are not accepted and the Commission will consider this issue in NPC’s next rate case/depreciation study.

H. Long-Term Avoided Cost

NPC Position

355. Mr. Pottey stated that NPC performed a Long-Term Avoided Cost ("LTAC") calculation for this filing and that these costs were based on the hourly marginal costs for the Preferred Plan. The LTACs that are listed in the filing assume that the avoidable unit is NPC’s large open position. Further, a capacity charge included in the market price forecast was added to the on-peak hours during the July through September period. (Exhibit 27 at 14.)

356. Mr. Pottey indicated that NPC proposes that the availability of LTAC rates be limited to a maximum of 25 MW of qualifying facility ("QF") contracts. (Exhibit 1, Volume VI at 65.)

Staff Position

\(^{18}\) Docket Nos. 05-10003 and 10004, Order at 87, paragraph 277, issued April 27, 2006;
357. Staff witness, Manual Lopez, Economist, provided Staff’s recommendations concerning the LTAC methodology and capacity limit proposed by NPC. (Exhibit 75 at 1.)

358. Staff recommended that the Commission:

   a) Require NPC to utilize the same LTAC methodology that was approved by the Commission in Docket No. 05-8004, including a capacity charge for the months of July through September but excluding external market sales;

   b) Approve a capacity limit of 75 MW for the purpose of calculating LTAC rates. (Id. at 1.)

359. Mr. Lopez stated that the methodology that NPC used to calculate its LTAC is different from the methodology that it has used in the past. NPC’s rates in this Application are based on what it would cost to secure the first megawatt hour (“MWh”) in a block and assumes this cost would remain the same for additional purchases within the block.

360. Mr. Lopez explained that the methodology that was approved by the Commission in Docket No. 05-8004 requires the utility to determine what it would cost for each successive MWh in a block and then average the cost of each MWh over the entire block. This methodology recognizes that there is a different cost associated with each additional MWh. If NPC uses this methodology its calculated LTAC rates would increase slightly. (Id. at 3.)

361. Mr. Lopez recommended that the Commission approve a capacity limit of 75 MW for the purposes of developing LTAC. Staff made this recommendation for the following three reasons:

   a) NPC is a much larger utility than SPPC with a larger open position;

   b) The 75 MW block size falls into the range of other contracts NPC has successfully signed with QFs in its service territory; and

   c) The 75 MW block size works better with NPC’s production cost model.

362. Mr. Lopez stated that SPPC did not get much of a response to the RFP that it issued to QFs and Staff does not expect NPC to fare much better. (Id. at 5.)

363. Mr. Maguire indicated that after SPPC filed its LTACs rates there was confusion regarding what procedure SPPC should follow if no one objected to the rates. The confusion could
be addressed if the Commission’s order regarding LTAC instructed the utility to go forward with its QF RFP if no one objects to the LTAC rates. (Tr. at 1044-1045.)

Commission Discussion and Findings

364. The Commission is convinced by Staff’s reasoning for requiring NPC to continue to use the methodology for calculating LTAC rates that was approved by the Commission in Docket 05-8004. This methodology will result in a more accurate LTAC calculation and is more representative of LTAC. Therefore, for the purpose of calculating a LTAC rate, NPC shall use the methodology that was approved by the Commission in Docket No. 05-8004.

365. With regard to the capacity limit on the availability of the LTAC rates, Staff’s argument that the limit should be increased to 75 MW because of NPC’s large open position justifies some movement away from the 25 MW limit proposed by NPC. The Commission believes that a 50 MW limit is a fair compromise given the divergent positions of NPC and Staff. Therefore, the Commission approves a 50 MW limit for the purpose of calculating LTAC rates.

366. Since the Commission is approving NPC’s Preferred Plan, NPC shall calculate LTAC rates based upon the Preferred Plan and shall file these rates as set forth in the Commission’s regulations.

IV. Phase IV Issues: SPPC Specific Issues

A. King’s Beach Replacement and Decommissioning Costs

SPPC Position

367. John Lescenski, Manager of Generation Asset Performance for SPPC and NPC, testified in support of SPPC’s proposal to replace the King’s Beach Diesel Units. (Exhibit 24 at 3.) SPPC requested Commission approval to expend $8.34 million to install 16 MW of diesel-fired reciprocating engines at the existing King’s Beach Plant Site in North Lake Tahoe. The new units will replace the existing King’s Beach units, which will not be permitted to operate after January 1, 2007 due to new environmental regulations in California. (Exhibit 2, Volume II-A at 104.)
368. Mr. Lescenski explained that the new units are essential for maintaining system reliability and operations in the Lake Tahoe area. The only viable alternative to replacing the King's Beach diesels is to upgrade the transmission system in and around the Lake Tahoe area. Assuming that the permitting of transmission system upgrades could be obtained, this alternative is projected to be much more costly and would not be available in time to support the system if these units are taken out of service. (Exhibit 2, Volume II-A at 104.)

369. Gary E. McDonald, Manager of Financial Planning and Analysis for SPPC and NPC, testified in support of SPPC's proposed accounting treatment for the retirement of the existing King's Beach Diesel units. SPPC requested Commission approval to establish a regulatory asset account in which to collect the retirement and decommissioning costs of the existing King's Beach generators and associated electric equipment. The structures, tanks, etc. will remain and be reused after the new generators are installed. While SPPC asserts that the King's Beach units have outlived their depreciable lives, there remains a net book value of approximately $385,000. SPPC requested regulatory asset treatment of these costs as well. (Exhibit 116 at 3-5.)

**BCP Position**

370. Jacob Pous, President of Diversified Utility Consultants, Inc., testified on behalf of BCP on the King's Beach Diesel Replacement. BCP recommended that the Commission deny SPPC's request for preapproval of decommissioning costs for the King's Beach units. The requested costs, if valid, should be booked as a plant addition cost of the replacement investment, given that the existing units will be removed to make room for the new units. Therefore, the Commission should not grant the establishment of a regulatory asset for the King's Beach replacement activity. (Exhibit 118 at 4, 6-8.)
Staff Position

371. Staff witness, Paul Maguire, testified on behalf of Staff on the engineering issues related to the King's Beach retirements. The existing King's Beach units total 16 MW of diesel-fired generation and were installed in 1969. The main purpose of these units is to provide backup/distributed generation in the North Lake Tahoe area, as the transmission system that feeds the northern part of Lake Tahoe is not very robust. Staff disagreed with Mr. McDonald's statement that the King's Beach diesel units had outlived their depreciable lives. Neither mechanical failure nor economic factors are driving the retirements. If it were not for the California regulations, the existing King's Beach units would likely continue to operate for many more years, especially in light of the limited number of operating hours on the units. (Exhibit 120 at 10.)

372. Mr. Maguire supported the installation of the replacement units noting that due to the severe winter weather (and forest fires) that can occur in and around the North Lake Tahoe area, some type of distributed generation is needed. Ideally, the best fix would be to install new transmission infrastructure up to the North Lake Tahoe area in order to improve reliability. Staff noted that SPPC investigated this alternative and concluded that permitting new transmission lines through the Lake Tahoe area would be a lengthy and difficult process. With respect to other alternatives, SPPC stated that the natural gas infrastructure in the North Lake Tahoe area would likely have to be significantly upgraded given that any natural gas-fired generation units would be required to operate in the winter months when natural gas heating demand is already at its highest level. Therefore, Staff recommended that the Commission approve the retirement of the King's Beach diesel units as the most practical alternative. (Exhibit 120 at 10-11.)

373. Staff witness, John Brownrigg, testified on the accounting treatment for the King's Beach units. Staff recommended that the Commission approve the establishment of a regulatory asset for the retirement and decommissioning costs for the King's Beach diesel units. The net book
value of the King's Beach units and related electric investment in accounts 101.344 and 101.345 would be transferred to a regulatory asset account in a subaccount of 182.3 at the time the generators are retired in January 2007. All decommissioning and remediation costs for the site would be accumulated in the account(s). However, these regulatory assets should be reduced by any salvage received for the retired assets. This is the same accounting treatment described in Mr. McDonald's testimony except that Staff addressed the salvage proceeds to reduce the cost of the newly created regulatory assets. Carrying charges equal to the currently approved AFUDC rate would be applied only on decommissioning and remediation costs (net of salvage proceeds) in the regulatory asset accounts. Carrying charges should not be applied to the undepreciated net book value of the retiring assets. The regulatory assets would be amortized at the current depreciation rate approved for those units until the rates from SPPC's next general rate case ("GRC") are implemented. This accounting treatment would apply only to that portion of the regulatory asset that relates to the unrecovered net book value. (Exhibit 119 at 2-5.)

**SPPC Rebuttal Position**

374. SPPC witness, Gary McDonald, testified that the Commission should accept Mr. Maguire's and Mr. Brownrigg's recommendation to approve the retirement and decommissioning of the King's Beach units and approve the establishment of regulatory assets to account for any undepreciated amounts and decommissioning costs. The Commission should accept the modification of accounting treatment proposed by Mr. Brownrigg for the recommended regulatory assets. (Exhibit 122 at 2.)

375. Mr. McDonald asserted that the Commission should reject Mr. Pous' recommendation that the net book value and decommissioning costs should be booked as a plant addition cost to the new units. (Exhibit 122 at 2.)
Commission Discussion and Findings

376. SPPC’s service territory covers approximately 50,000 square miles in northern Nevada, and the Lake Tahoe area of northeastern California. While SPPC operates in two states, it only operates as a single system. Customers in both jurisdictions enjoy the benefits of a single system which include economies of scale and reliability. SPPC must comply with the applicable federal, state and local statutes, regulations and ordinances in which it operates and the costs of such compliance is typically included in general rates paid by all customers.

377. In this instance, a change in environmental regulations in the State of California requires the early retirement of the King’s Beach diesel units. These units have been used to reinforce reliability in the North Tahoe area. The testimony of BCP, Staff and SPPC indicates that there is no issue with respect to the fact that the units must be removed. Further, there seems to be no disagreement that steps must be taken to increase reliability in this area. Staff’s testimony indicates that SPPC considered a number of alternatives including transmission, installation of natural gas units, and new diesel units. The Commission agrees with Staff and SPPC that the installation of new diesel units is the best alternative at this time. Therefore, the Commission approves SPPC’s request for the expenditure of $8.34 million to decommission and replace the existing King’s Beach diesel fired generating units.

378. With respect to SPPC’s request to establish a regulatory asset account for the existing King’s Beach diesels except for capital items, such as structures and tanks that will be used in the new units, the Commission approves this request as modified by Staff and agreed to by SPPC in its rebuttal testimony.

379. The Commission rejects BCP’s recommendation that the net book value and decommissioning costs be booked as a plant addition cost to the new units. The Commission finds that BCP’s interpretation of the USA is not appropriate under these circumstances. The FERC USA
for electric utilities provides that land acquisition costs for new electric facilities specifically
exclude the cost of removing a preexisting utility plant. In this case, booking the costs of removing
the King’s Beach units as a cost related to the new units would be inconsistent with the FERC USA.

B. Portola Diesels

SPPC Position

380. John Lescenski, Manager of Generation Asset Performance for SPPC and NPC,
testified in support of SPPC’s proposal to retire diesel units at Portola, California. (Exhibit 24 at 3.)
SPPC seeks approval to establish a regulatory asset account for the retirement and decommissioning
of the Portola diesels units. Sierra was required to shut down these units on January 1, 2006, as
they were no longer operable within environmental operating constraints. While these units have
outlived their depreciable lives, there remains a net book value of approximately $157,000.
Additionally, there will be costs associated with the removal and decommissioning of each unit.
(Exhibit 2, Volume II-A at 105.)

BCP Position

381. BCP witness, Jacob Pous, recommended that the Commission deny SPPC’s request
for preapproval for the decommissioning cost for the Portola units. SPPC has not yet determined
the extent of the decommissioning/remediation costs for these units. All valid costs can be
addressed in the next rate case. The timing of the recognition of the retirement process for the
Portola units is of such a small magnitude that it will not affect SPPC’s financial integrity. (Exhibit
118 at 5.)

Staff’s Position

382. Staff witness, Paul Maguire, supported SPPC’s plan to retire the Portola units,
observing that retirement of the units is really no more than a formality at this point given that
SPPC stopped operating the units as of January 1, 2006, due to the California regulation that is also
forcing the retirement of the King's Beach units. The Portola units have not outlived their
depreciable lives; the units are being shut down because of the environmental policy by the State of
California. The capacity that these units provide will have to be replaced either in the form of new
generating units located elsewhere or in the form of purchased power products. (Exhibit 120 at 14.)

383. Mr. Maguire stated that Staff does not know what the actual costs of
decommissioning these units would be, and these costs would have to be examined in the
appropriate GRC proceeding. However, the diesel units being retired should have some value on
the secondary market. Given the low number of operating hours, the salvage value of these units
should be significant, and depending on the amount of site remediation that has to be performed, the
salvage value could equal the decommissioning costs. SPPC should attempt to sell the units to help
minimize any decommissioning costs. (Exhibit 120 at 14-15.)

384. Staff Witness, John Brownrigg, recommended that the Commission approve the
establishment of a regulatory asset for the retirement and decommissioning costs for the Portola
diesel units, and transfer the net book value of the Portola units into accounts 101.341, 101.342,
101.344 and 101.345 to a regulatory asset in a subaccount of account 182.3. All decommissioning
and remediation costs for the sites would be accumulated in the regulatory asset accounts.
However, these regulatory assets should be reduced by any salvage received for the retired assets.
This is the same accounting treatment described by Mr. McDonald except that Staff included
additional language to include salvage proceeds to reduce the value of the newly created regulatory
assets. Carrying charges equal to the currently approved AFUDC rate would be applied only to
decommissioning costs (net of salvage proceeds) in the regulatory asset accounts, and should not be
applied to the undepreciated, net book value of the retiring assets. The regulatory assets would be
amortized at the current depreciation rate approved for those units until the rates from SPPC's next
GRC are implemented. This accounting treatment should apply only to that portion of the regulatory asset that relates to the unrecovered net book value. (Exhibit 119 at 2-5.)

**SPPC Rebuttal Position**

385. SPPC witness, Gary McDonald, recommended that the Commission accept Staff’s recommendation to approve the retirement and decommissioning of the Portola diesel units and approve the establishment of regulatory assets for any undepreciated amounts and decommissioning costs. The Commission should accept the modification of accounting treatment proposed by Staff for the recommended regulatory assets. (Exhibit 122 at 2.)

**Commission Discussion and Findings**

386. As noted in the Commission’s discussion of the King’s Beach diesels above, SPPC has to comply with the applicable federal, state and local statutes, regulations, and ordinances in which it operates, and the costs of such compliance is typically included in general rates and shared by all customers. In this case, a change in environmental regulations in the State of California will require the early retirement of the Portola diesels. Therefore, the Commission approves SPPC’s request to approve the retirement of the Portola diesels.

387. With respect to SPPC’s request to establish a regulatory asset account for the units, the Commission approves this request as modified by Staff and agreed to by SPPC in its rebuttal testimony.

**C. Piñon Pine Gasifier Decommissioning Costs**

**SPPC Position**

388. John Lescenski, Manager of Generation Asset Performance for SPPC and NPC, testified in support of SPPC’s proposal to retire the Piñon Pine gasifier and related facilities. (Exhibit 24 at 3.) SPPC requested authority to expend $1.2 million to decommission the Piñon Gasifier Island ($200,000 for engineering and $1 million for demolition). SPPC began construction
of the Piñon Pine facility in 1995. The Gasifier Island, materials handling system, nitrogen plant, and auxiliaries were completed in 1997, but were mothballed in 2001. (Exhibit 2, Volume II-A at 106.)

389. Mr. Lescenski stated that in December 2005, SPPC sent an RFP to six parties that had expressed an interest in coal gasification or had experience in operating gasifiers. The RFP was intended to determine if anyone was interested in making the necessary investment and operating the Piñon Gasifier and providing a fuel supply agreement to SPPC for the Syngas produced by the Piñon Gasifier. No party expressed interest in the RFP, confirming SPPC’s determination that this in an outdated technology and the risk is too great to warrant the investment of any additional resources in the Piñon Gasifier. (Exhibit 2, Volume II-A at 107.)

390. Mr. Lescenski recommended decommissioning of the gasifier and related facilities. Despite the failure of the Kellogg-Rust-Westinghouse technology, all of the gasification equipment is still in good condition and some of it is expected to resell on the used equipment market. The rest will be salvaged at scrap value. (Id.)

BCP Position

391. BCP witness, Dale Stransky, recommended that SPPC’s request for preapproval for Piñon Gasifier decommissioning costs be denied. The cost of decommissioning the Piñon Gasifier could approximately equal the resale value of the equipment and scrap. Therefore, there should be no net decommissioning costs or additions to plant in service. If such costs are not denied, they should be recognized as a part of the new facilities at the Tracy Station and accounted for as new plant in service. (Exhibit 118 at 11.)

Staff Position

392. Staff witness, Paul Maguire, recommended that the Commission reject SPPC’s request to spend $1.2 million to decommission the Piñon Pine Gasifier. Staff noted that the reason
for decommissioning at this time, instead of when the Piñon Pine is retired, is that the gasifier equipment is interfering with the construction of the new Tracy unit. If SPPC needs to decommission the gasifier and associated equipment it should do so and the net cost of decommissioning, if any, can be considered for recovery by the Commission in the context of a GRC. (Exhibit 120 at 6-7.)

**SPPC Rebuttal Position**

393. SPPC witness, John Lescenski, clarified that decommissioning costs of $1.2 million represents $200,000 for a contract with Sigma Engineering to assist with preliminary engineering and with creation of a document that will be used to negotiate a final decommissioning price through a bid process. The $1 million was an estimate of the total decommissioning costs net of any salvage proceeds. The $1 million amount is an estimate for decommissioning the entire gasifier even though it will be dismantled in phases. (Exhibit 122 at 2-3.)

394. Mr. Lescenski noted that given the history of the Piñon project, the Company was asked during discovery to explain why it is seeking recovery of decommissioning costs when the Commission disallowed rate base treatment of the project in Docket No. 03-12002. SPPC disagrees that Piñon was entirely disallowed. The Commission's order in the above docket reiterated that building Piñon was prudent and in the public interest even though the gasifier technology did not prove out. However, the Commission disallowance of these costs was due to the fact SPPC did not file resource plan amendments as it should have when it discovered significant cost overruns, not because they were imprudent. SPPC believes that decommissioning costs for Piñon should be recoverable. (Id. at 3.)

395. Mr. Lescenski did concede that the request for approval of decommissioning costs in this filing is premature. Instead, SPPC proposed to accumulate decommissioning costs in an account and will present them in the next GRC for recovery. (Id.)
Commission Discussion and Findings

396. The Commission finds that request for approval of the amount in this filing is premature. The Commission directs SPPC to accumulate decommissioning costs and associated salvage receipts in an account and provide such costs for Commission consideration for recovery in the first GRC following the completion of decommissioning.

397. The Commission rejects BCP’s proposal that the costs be assigned to the new Tracy plant. The FERC USA for electric utilities provides that land acquisition costs for new electric facilities specifically exclude the cost of removing a preexisting utility plant.

D. Upgrade the Combustion Systems at Valmy Generating Station

SPPC Position

398. SPPC witness, John Lescenski, sponsored the portion of the Thirteenth Amendment relating to the Valmy Combustion Upgrades. (Exhibit 24 at 2-3.)

399. Mr. Lescenski stated that SPPC is requesting Commission approval to upgrade the combustion systems on Valmy Units 1 and 2. SPPC’s share of the cost for this upgrade is $4 million. Without the additional combustion control equipment, Valmy 1 and 2 will not operate without violating environmental regulations and will need to be shutdown as of December 31, 2007. (Exhibit 2, Vol. II-A at 105.)

Staff Position

400. Staff witness, Jon Davis, provided Staff’s recommendations regarding SPPC’s request to upgrade the combustion systems at Valmy Units 1 and 2. (Exhibit 52 at 2.) He recommended that the Commission approve SPPC’s request for these upgrades. (Id. at 3.)

401. Mr. Davis stated that the NDEP is requiring SPPC to install the systems at Valmy by January 1, 2008 as a result of prior agreements. (Id. at 55.)
BCP Position

402. BCP witness, Dale Stransky, provided testimony recommending that the Commission approve SPPC's request to upgrade the combustion systems at Valmy Units 1 and 2 at a cost of $4 million. (Exhibit 80 at 2.)

Commission Discussion and Findings

403. SPPC requested Commission approval of upgrades to the combustion systems at Valmy that would allow the units to operate beyond December 31, 2007. SPPC’s share of the cost of these upgrades is expected to be $4 million. Staff and the BCP supported SPPC’s request for these upgrades. No other parties opposed the expenditures for these upgrades.

404. The capacity and energy from the Valmy units are vital resources required by SPPC in order to meet their customer demand at a reasonable cost. The upgrades to the combustion systems at Valmy are required in order for the continued operation of these units beyond December 31, 2007. The cost for the upgrades appears to be reasonable. Therefore, the Commission finds that SPPC’s request for Commission approval to upgrade the combustion systems at Valmy Units 1 and 2 is approved at a cost of $4 million.

E. Convert Backup Fuel Systems at Tracy From Oil to Diesel

SPPC Position

405. SPPC witness, John Lescenski, sponsored the portion of the Thirteenth Amendment and its technical appendix relating to the conversion of the back-up fuel system at Tracy from oil to diesel. (Exhibit 24 at 2-3.)

406. Mr. Lescenski stated that SPPC is requesting $980,000 for the conversion of the Tracy Units 2 and 3 back-up fuel systems from No. 6 oil to No. 2 diesel. No. 2 diesel, while higher in cost than the No. 6 oil, is a cleaner burning fuel and provides lower emission rates when these units are required to operate on their back-up fuel. The conversion is an environmental improvement project, will potentially provide additional air increment in the Tracy air basin and may potentially aid in the economic development of the surrounding area. A detailed report by
Zachry is provided in the Supply Side section of the Thirteenth Amendment’s Technical Appendix. (Exhibit 2 at 106.)

**Staff Position**

407. Mr. Maguire provided Staff’s recommendations regarding the SPPC’s request to convert the back-up fuel systems used for Tracy Units 2 and 3 from No. 6 oil to No. 2 diesel. Staff recommended that the Commission deny SPPC’s request for this conversion. (Exhibit 120 at 1-2.)

408. Mr. Maguire explained that SPPC is requesting the conversion at Tracy Station to comply with the terms of a “Memoranda of Understanding” it entered into with Storey County as a result of negotiations over the issuance of the new Tracy 500 MW combined cycle unit special use permit. The purpose of the conversion appears to be to reduce the emissions at Tracy Station to free up air shed in the Reno-Tahoe Industrial Park to allow further development in the area. (Id. at 7.)

409. Mr. Maguire stated that Staff supports further development in the Reno-Tahoe Industrial Park, but it does not believe that SPPC’s ratepayers should support the cost for this development. SPPC’s request as proposed would be detrimental to SPPC’s customers in at least three ways: (1) the air shed that is given up would no longer be available for future generation expansion at Tracy; (2) SPPC’s customers would have to pay for the cost of conversion without receiving any benefit; and (3) the back up fuel that SPPC is proposing to convert to is more expensive than the current back-up fuel which will result in increasing costs to SPPC’s ratepayers. Additionally, at a minimum, the cost for the conversion should be borne by either Storey County or developers that need the additional air shed. (Id. at 8.)

410. Mr. Maguire stated that SPPC may have other options to help Storey County and the Tahoe-Reno Industrial Park that would result in minimal costs to ratepayers and that Staff would not be opposed to SPPC pursuing some of these options. (Id. at 8.)

**BCP Position**

411. BCP witness, Dale Stransky, provided testimony recommending that the Commission approve SPPC’s request to expend $980,000 to convert the back-up fuel system used for Tracy Units 2 and 3 from No. 6 oil to No. 2 diesel. (Exhibit 80 at 2.)
Commission Discussion and Findings

412. The Commission recognizes the importance of Reno-Tahoe Industrial Park to Storey County and the western Nevada Economy, but in this case finds that Staff's recommendations are in the best interest of SPPC's ratepayers. Expenditures of $980,000 to released air shed for Reno-Tahoe Industrial Park developers provide a general benefit to the population but not a specific benefit to SPPC's customers. SPPC should take Staff's recommendation and consider other methods to free up air shed that does not have negative cost consequences for its ratepayers. Therefore, SPPC's requested back-up fuel conversion at Tracy is denied.

F. Expenditures for Participation in WestConnect RTO and Regional Planning

SPPC Position

413. Brian Whalen provided testimony supporting SPPC's request for Commission approval of expenditures for continued participation in WestConnect and for regional studies and is sponsoring the portions of the Thirteen Amendment related to these expenditures. (Exhibit 35 at 2; Exhibit 2, Volume II-A at 98-104.) With regard to the WestConnect expenditures, SPPC is requesting that the Commission approve $32,000 in 2006, $33,000 in 2007, $34,000 in 2008 and $35,000 in 2009. With regard to the regional studies he stated that SPPC is requesting approval to expend $250,000 in 2007 for regional planning costs relating to the Frontier Line Transmission and other regional transmission projects. (Exhibit 2 at 5.)

414. With regard to the expenditures for participation in WestConnect, Mr. Whalen noted the Commission ordered it to participate and fund its share of the WestConnect development. He indicated that WestConnect is a group of southwest transmission providing utilities that have agreed to work collaboratively to assess stakeholder and market needs and to investigate, analyze and recommend cost-effective enhancements to the western wholesale electricity market. (Id. at 100.)

415. Mr. Whalen stated that SPPC is requesting the funds for the Regional Studies to perform feasibility analysis for long-term strategic planning of major Western Interconnection proposals such as the Frontier Line. These projects differ from SPPC's normal planning as they are long lead time joint projects, they affect the operation of the entire Western Interconnection, and
they involve numerous other entities. (Exhibit 35 at 5.) The expenditures are required in order to
determine if the Frontier Line Project is feasible and beneficial in comparison to other resource
alternatives available to SPPC and others participating in the feasibility analysis. (Id. at 103.)

Staff Position

416. Mr. Maguire provided testimony addressing SPPC’s request for Commission
approval of expenditures for continued participation in WestConnect and for Regional Planning
studies related to the Frontier Line Project. (Exhibit 120 at 2.)

417. With regard to SPPC’s request for Commission approval for expenditures for
Regional Planning Studies, Mr. Maguire stated that it is imperative that SPPC participate, and in
some cases, take a leading role in the regional projects that are currently being evaluated for the
Western Interconnection. Failure to participate in these studies would leave SPPC and its
ratepayers at a severe disadvantage as issues that would help or hinder Nevada would go
undiscovered. (Id. at 15.) Staff recommended that the Commission approve SPPC’s request for
Commission approval of $250,000 to participate in regional planning activities in 2006 and 2007.
(Id. at 16.)

418. With regard to SPPC’s request for Commission approval for expenditures for
continued participation in WestConnect, Mr. Maguire recommended that the Commission approve
SPPC’s request but limit approval to only those expenditures required in 2006 and 2007. SPPC can
make a request for additional funding in 2008 and 2009 in its upcoming 2007 IRP. (Exhibit 120 at
16-17.)

BCP Position

419. Dale Stransky recommended that the Commission approve SPPC’s request to expend
$250,000 for study costs related to the Frontier Line and other regional transmission projects.
(Exhibit 80 at 2.)

Commission Discussion and Findings

420. SPPC requested Commission approval for expenditures for continued participation in
the WestConnect Regional Transmission Organization (“RTO”) and for Regional Planning studies
related to the Frontier Line Project. Staff supported SPPC's request but recommended that with respect to the WestConnect participation expenditures that Commission approval be limited to only those funds needed for 2006 and 2007. The BCP recommended Commission approval for the WestConnect RTO and Regional Planning studies expenditures.

421. The Commission finds that SPPC's request for approval of expenditures for WestConnect participation and for Regional Planning studies is approved for the reasons listed above by Mr. Whalen and Mr. Maguire. The Commission is approving SPPC's request for funding for WestConnect participation through 2009. If funding requirements change, SPPC may update its request for expenditures related to participation in WestConnect in its next IRP. Therefore, the Commission approves: (1) SPPC's request for expenditures for participation in WestConnect for $32,000 in 2006, $33,000 in 2007, $34,000 in 2008 and $35,000 in 2009; and (2) SPPC's request to expend $250,000 in 2007 for regional transmission studies to evaluate the feasibility of the Frontier Line and other proposed projects.

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THEREFORE, based upon the foregoing findings and conclusions, it is ORDERED that:


2. The Commission retains jurisdiction for the purpose of correcting any errors that may have occurred in the drafting or issuance of this Order.

By the Commission,

[Signature]
DONALD L. SODERBERG, Chairman and Presiding Officer

[Signature]
JO ANN P. KELLY, Commissioner
(Dissenting on Paragraphs 211 and 212.)

[Signature]
REBECCA D. WAGNER, Commissioner

Attest: Cristal Jackson
CRYSTAL JACKSON, Commission Secretary

Dated: Carson City, Nevada

11-19-06
(SEAL)