

**BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

Second application of ROUSE FASHION SHOW ) MANAGEMENT, LLC to purchase energy, ) capacity and/or ancillary services from a provider of ) new electric resources. ) _____ )	Docket No. 02-5003
Second application of COAST HOTELS AND ) CASINOS, INC. to purchase energy, capacity ) and/or ancillary services from a provider of new ) electric resources. ) _____ )	Docket No. 02-5004
Second application of STATION CASINOS, INC. ) to purchase energy, capacity and/or ancillary ) services from a provider of new electric resources. ) _____ )	Docket No. 02-5005
Second application of GORDON GAMING CORP., ) d/b/a SAHARA HOTEL AND CASINO to purchase ) energy, capacity and/or ancillary services from a ) provider of new electric resources. ) _____ )	Docket No. 02-5006
Second application of MGM MIRAGE to purchase ) energy, capacity and/or ancillary services from a ) provider of new electric resources. ) _____ )	Docket No. 02-5007

At a general session of the Public Utilities  
Commission of Nevada, held at its offices on  
July 31, 2002.

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

ABSENT: Commissioner Richard M. McIntire

**ORDER**

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

**I. PROCEDURAL HISTORY**

1. On May 2, 2002, Applications were re-filed with the Commission by Rouse

Fashion Show Management, LLC; Coast Hotels and Casinos, Inc.; Station Casinos, Inc.; Gordon Gaming Corp., d/b/a Sahara Hotel and Casino; and MGM Mirage to exit the system of Nevada Power Company ("NPC") and to purchase energy, capacity and/or ancillary services from a provider of new electric resources. These matters have been designated as Docket Nos. 02-5003, 02-5004, 02-5005, 02-5006, and 02-5007, respectively (collectively the "Applications"). Rouse Fashion Show Management, LLC; Coast Hotels and Casinos, Inc.; Station Casinos, Inc.; Gordon Gaming Corp., d/b/a Sahara Hotel and Casino; and MGM Mirage are collectively referred to as the "Applicants".

2. The above Applications have been filed pursuant to the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), including but not limited to NRS 704B.310 and NAC 704B.310. Pursuant to NAC 704B.340 and NAC 703.5274, the Applicants have requested that certain information be treated as confidential material.

3. The Commission issued public notices of these Applications in accordance with State law and the Commission's Rules of Practice and Procedure.

4. NPC, Nevada Independent Energy Coalition ("NIEC"), and Reliant Energy Services ("Reliant") have been granted full intervenor status (collectively "Intervenors"). The Regulatory Operations Staff ("Staff") of the Commission and the Attorney General's Bureau of Consumer Protection ("BCP") participated as a matter of right.

5. On May 2, 2002, the Applicants filed a Joint Motion to Consolidate Dockets 02-5003, 02-5004, 02-5005, 02-5006, and 02-5007 ("Joint Motion to Consolidate").

6. On May 7, 2002, Staff filed a Response to the Joint Motion to Consolidate.

7. On May 8, 2002, the Presiding Officer issued a Procedural Order, which consolidated the Applications and established a procedural schedule.

8. On May 10, 2002, the Applicants, Staff, BCP, NPC, and NIEC filed methodology briefs. Reliant filed a Joinder to the Applicants' methodology brief.

9. On May 14, 2002, a Notice of Hearing was issued.

10. On May 21, 2002, the Presiding Officer issued Procedural Order No. 2.

11. On May 24, 2002, Staff filed its final analysis.
12. On June 4, 2002, a Notice of Cancellation of Hearing and Notice of Hearing was issued, which rescheduled the hearing date to July 18, 2002.
13. On June 13, 2002, the Presiding Officer issued Procedural Order No. 3.
14. On June 24, 2002, an Order Granting Requests for Protective Orders was issued.
15. On June 25, 2002, the Applicants, BCP, and NPC filed alternative analyses pursuant to NAC 704B.350, while Reliant filed a Statement in Support of the alternative analysis of the Applicants. Also on June 25, 2002, Applicants, Staff, BCP, and Intervenors filed Stipulations in the respective dockets.
16. On June 28, 2002, NPC refiled its alternative analysis.
17. On July 1, 2002, the Applicants filed a joint position paper, while Staff, BCP, Reliant and NPC filed individual position papers.
18. On July 18, 2002, a duly-noticed hearing was commenced to take evidence on those issues not resolved by the Stipulations.

## **II. EXIT FEE**

### **Staff's Position**

19. Staff recommends that only Rouse be charged an exit fee other than their share of the DEAA balance as Staff believes that both NPC and the remaining customers will not be negatively impacted by the departure of these eligible customers. (Exhibit 11 at p. 3, 23; Attachments RLK-2 through RLK-6; and Closing Brief.) Mr. Ron Knecht, Staff's witness, states that Staff's analysis for the determination of the non-DEAA impacts consists of four components: 1) loss of revenues associated with the eligible customer switching from bundled service to unbundled service; 2) a forecasted value-based estimate of reduction in utility operating and procurement costs; 3) the effect of the eligible customer's switch in reducing rates that the remaining customers will pay in future years; and 4) net reduction in risks and contingent costs to NPC not reflected in the forecasted reduction in NPC's operating and procurement costs. The net impact was determined by subtracting the latter three components from the first component. The

present value of the net impact was determined using an 11.44 percent discount rate. (*Id.* at p. 3.)

20. Staff explains that lost revenue is the difference between the revenue NPC would receive from these customers under bundled service and revenue it obtains from the provision of unbundled services (transmission and/or distribution). The lost revenues developed by NPC were adjusted to eliminate the reduction in mill assessment as the departing eligible customer is still required to continue to pay these fees. (*Id.* at p. 4-5.)

21. Mr. Knecht states that the forecasted value-based operating and procurement cost reductions were obtained by comparing two NPC PROMOD modeled simulations of its system. NPC modeled its system with and without the eligible customer's load. The difference in the two simulations represents the eligible customer's estimated impact upon NPC's operating and procurement costs. (*Id.* at p. 8.)

22. Mr. Knecht states that the effect of the eligible customer's switch in reducing the rates that the remaining customers would pay in future years could be considered the "load-growth effect". Mr. Knecht asserts that the future Base Tariff General Rates ("BTGRs") would be set lower than the existing BTGRs due to the generation function's revenue requirement declining on a per customer basis. He explains that the future decline in the "generation function" revenue requirement is caused by both the reduction of the purchase of power to meet load growth and the decline in generation plant due to depreciation. Mr. Knecht states that NPC calculated the lost revenues associated with the eligible customers by presuming that the same BTGRs would be in effect during the entire three year analysis period. As a result, the "load-growth effect" was not incorporated into the lost revenue calculation. Mr. Knecht estimates the benefit to be less than three percent of NPC's estimated lost revenues. Mr. Knecht argues that the eligible customer should not relinquish this bundled service benefit for "power-market freedom". (*Id.* at p. 5-7.)

23. Staff asserts that the PROMOD simulations do not consider all of the net reduction in risks and contingent costs that NPC would experience. Mr. Knecht recommends two alternative methods for evaluating this understatement, a probabilistic assessment and a "capacity credit". (*Id.* at p. 9, 13, and 14.) Staff opines that a probabilistic analysis rather than a

deterministic approach should be applied. According to Mr. Knecht, the Parties agree that the range of probabilities concerning purchased power and natural gas (primary fuel) prices is a low of 50 percent of NPC's base case and a high of 150 percent of NPC's base case. Staff assigns a probability factor of 10 percent to each the high and low cases and 80 percent to the base case. Staff bases its opinion upon an observation that, as with all commodities, prices for natural gas and prices for purchase power are "characterized by occasional rapid excursions upward followed by collapses back down to the previous levels and relatively long periods at those levels before the next fly-up and collapse" and that the 2000-2001 market was a classic example of this behavior. Further, Staff opines that NPC's prices are the most likely prices for a deterministic analysis as the prices are based upon a market survey, which are adjusted for a credit risk premium of \$1.50 per MWh and \$0.15 per decatherm of natural gas. However, Staff expresses doubt that NPC's forecasted prices would be experienced as the surveys of brokers included prices for terms of less than three years due to the market being "too thin to yield reliable quotes". Further, since NPC's supply portfolio includes a mixture of long-term and shorter-term supplies no guarantee exists that these prices will prevail in NPC's future procurement. (Id. at p. 9-12.)

24. Alternatively, Staff asserts that it is appropriate to use a foregone generation capacity option, "capacity credit", as surrogate for considering the effects of the high and low cases. Staff states that NPC currently does not have an approved "bulk-power" integrated resource plan that reflects the statutory changes made by the 2001 Nevada Legislature that placed NPC "back into the power supply business on a owned-cost basis." Mr. Knecht argues that, due to the "2000-2001 fuel and purchase-power fly-up", it is reasonable to anticipate that any integrated resource supply plan approved today would focus on NPC owning generation to supplement its current generation, which supplies less than 50 percent of its current requirements. Therefore, any foregone capacity addition associated with the departure of the eligible customer should inure to that customer. Staff states that, in order to implement this alternative, it would be necessary to eliminate purchased power capacity costs from the PROMOD determined operating and procurement costs. (Id. at p. 12-14.)

25. Staff states that its selection of a three year analysis period is due to NPC's procuring fuel and purchased power contracts with terms not exceeding three years and to the long-term tendency of prices under such contracts to revert to mean historic levels. Therefore, no basis exists for forecasting any material cost accumulation beyond three years after the service switch date. (*Id.* at p. 14-15.)

26. Staff also proposes a discount rate of 11.44 percent. Staff argues that, in order to ensure indifference between the remaining customers, it is appropriate to determine the discount rate from the customers' perspective. Mr. Knecht asserts that empirical economic literature on the discount rate issue quantified the average real, not inflation adjusted, residential ratepayer discount rate to be in excess of 10 percent. Further, Staff asserts that the literature on social opportunity cost of capital is that of a typical company inherently has a cost greater than cost regulated firms. Additionally, Staff asserts that its approach is consistent with the highest court precedent on the subject, *Northern California Power Agency v. F.E.R.C.*, 37 F.3d, 1517 (D.C. Cir. 1994). Mr. Knecht explains that Staff quantifies its 11.44 percent discount rate by using NPC's gross cost of capital, the estimated marginal costs of debt and preferred stock, the Commissions determined 10.1 percent return on common equity, a 35 percent marginal federal income tax rate, and NPC's capital structure as authorized in Docket No. 01-10001. (*Id.* at p. 19-20.)

Position of Station Casinos, Inc.; Coast Hotels and Casinos, Inc.; Gordon Gaming Corp. d/b/a Sahara Hotel and Casino; and Rouse Fashion Show Management, LLC

27. Mr. Gildersleeve states on behalf of Station, Coast, Sahara and Fashion Mall that NPC's alternative analysis filed on June 25<sup>th</sup> overstates the Fashion Show Mall's projected electricity usage. (Exhibit 7 at p. 2 and 5.) Mr. Gildersleeve states that in both the initial and current Fashion Show Mall applications the electricity usage was estimated to be more than double the existing current levels due to its current expansion. However, he has subsequently updated the forecast using internal budget documents. Mr. Gildersleeve asserts that his current estimate of future electricity usage is the best estimate available; thus, it should be used in the exit fee analysis. Further, Mr. Gildersleeve asserts that NPC's estimated electricity usage forecast is

flawed because of the following: (1) it relies upon an incorrect relationship between connected load and peak load (not all peaks occur simultaneously), (2) it ignores the gradual ramping of the CES central plant, and (3) it ignores decreases in historical usage as in-line tenants convert to more efficient CES central plant water-based cooling. Mr. Gildersleeve explains that the CES central plant will provide chilled water for HVAC needs in the common areas and, ultimately, for all line tenants. (Id. at p. 3-6 and Attachment DJG-3.) Further, Mr. Gildersleeve provides a revision to the exit fee calculation for various parties using the correct projected electricity usage. (Id. at p. 6-7 and Attachment DJG-4.)

28. Dr. Berry recommends that the departing eligible customers be afforded their load ratio share of both a load-growth credit and a capacity credit, which are similar to Staff's proposed adjustments as set forth in Staff's final analysis (filed May 24<sup>th</sup>). (Exhibit 19 at p. 1-2.)

29. Dr. Berry explains that the "load-growth credit" was intended to capture the economic benefits the customer would have received had it remained a customer and would be limited to the generation related component of the bundled rate. Dr. Berry asserts that NPC would earn excess revenues from future, and existing, customers as system energy use increases over time. Further, Dr. Berry states his clients were in agreement with Staff's "load-growth credit". Also, Dr. Berry states his clients acquiesced with NPC that no Base Tariff Energy Rate ("BTER") load-growth credit was warranted. (Id. at p. 2 and 4.)

30. Dr. Berry argues a capacity credit is necessary to acknowledge that NPC's PROMOD simulations do not capture all the avoided costs. For example, in the face of market anomalies all capacity costs may not be captured in the forecasted forward price used in the simulation. Further, Dr. Berry argues that the departure of the eligible customers allows NPC controlled or owned generation to become a larger percent of the energy mix for remaining customers. Additionally, Dr. Berry concurs with Staff's assessment that NPC's additional avoided capacity beyond that modeled in PROMOD should be analyzed and, if warranted, be applied as an additional credit to any exit fee paid by departing eligible customers. (Id. at p. 4-5.)

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MGM / Mirage's Position

31. Mr. Garrett, MGM / Mirage's witness, recommends that the departing customer be afforded a load-growth credit and afforded the reduced market price benefit created by its departure. (Exhibit 20 at p. 7-9 and Attachment MG-1.) Mr. Garrett summarizes the various exit fee issues raised by the Parties upon which an agreement had been reached and noted that NPC made a commitment to include all these changes in a revised analysis to be filed with the Parties by July 1<sup>st</sup>. (Id. at p. 3-6 and 11.) However, Mr. Garrett notes that four exit fee issues remain unresolved: 1) The benefits associated with system load growth not captured in the PROMOD simulations; 2) Avoided capital expenditures costs for new generation capacity; 3) Reduced risk exposure to market price volatility, when a greater percentage of NPC's power portfolio is produced with NPC owned capacity rather than purchased on the open market; and 4) The discount rate to be used to determine the net present value of the future benefits and costs. (Id. at p. 6-7.) Mr. Garrett's exit fee calculation incorporates both the resolved issues and his position on the unresolved issues. (Attachment MG-1.)

32. Mr. Garrett concurs with Staff that a load-growth adjustment is appropriate and that Staff has reasonably calculated the load growth benefit. He asserts that the adjustment provides the departing eligible customer with its equitable share of the intrinsic benefits that are derived from spreading fixed generation costs over an expanding customer base. Mr. Garrett argues that the departing eligible customer pays its full share of fixed generation costs embedded in rates in the form of the exit fee and forfeits its share of the reduction in fixed generation costs that naturally accrues through customer growth. Further, the PROMOD avoided cost production analysis does not capture this fixed generation cost impact as it only measures the changes in variable generation costs. Mr. Garrett's exit fee calculation includes this adjustment. (Id. at p. 7-9 and Attachment MG-1.)

33. While Mr. Garrett believes that the departure of an eligible customer does provide the remaining customers a reduced market price risk benefit, Mr. Garrett's exit fee analysis filed with his direct testimony does not include an amount. Mr. Garrett states that he would include an

amount after the Parties had an opportunity to review and discuss the sensitivity analysis provided by NPC. Mr. Garret explains that Staff described its capacity credit calculation, contained in its May 24<sup>th</sup> exit fee analysis, as a means to capture the reduced market price risk benefits the remaining customers derive by NPC procuring a reduced portion of its power requirements on the open market. Mr. Garrett states that subsequent collaborative discussions suggested that this risk may be assessed by examining the PROMOD avoided production cost sensitivity to market price extremes and that NPC agreed to, and did, provide sensitivity runs. Mr. Garrett notes that Dr. Berry's calculations, provided and discussed during the collaborative process, demonstrates that the departure of the five Applicants would delay NPC's planned addition of 446 MW of generation capacity in 2007 to 2008, as set forth in NPC's last integrated resource plan (Docket No. 01-7016). (Id. at p. 9-10 and Attachment MG-1.)

34. Mr. Garrett opines that Staff's discount approach is reasonable as it appropriately focuses on the consumer's cost of money. (Id. at p. 11.)

35. Mr. Garrett disagrees with NPC's recommendation that an exit fee be recalculated immediately prior to the eligible customer departing the system<sup>1</sup>. He argues that the Commission must base its decision on whether a customer should be allowed to leave the system based upon the evidence submitted at the hearing. Further, assuming the Commission approves the eligible customer's departure, from a business perspective the recommendation is unworkable as the information is a vital component in the customer's decision of whether or not to actually leave the system. (Id. at p. 12.)

#### BCP's Position

36. Dr. Polito, BCP's witness, recommends the following to the Commission: 1) use the base case avoided cost estimate in the determination of the exit fee; 2) determine the exit fee as the difference between the lost revenues and avoided costs without reduction for either Staff's proposed capacity credit or load-growth credit; and 3) the Commission ignore "Staff's reported

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<sup>1</sup> On June 25, 2002, NPC filed an alternative analysis. NPC recommended that Staff file an updated analysis at the time the applicants submit their intent to proceed under NAC 704B.380.1. If the impact fee changed by more than 10 percent the applicants would be charged the revised fee.

existing subsidy and 10 percent credit measures” in its determination of the exit fee. (Exhibit 24 at p. 2.)

37. Dr. Polito asserts that consideration of the high and low avoided cost cases in the determination of the impact fee is equivalent to stating that the “market’s expectation of future supply and demand conditions was incorrect”. Further, Dr. Polito asserts that consideration of these scenarios has a greater probability of reducing the accuracy of the analysis rather than increasing its accuracy. Dr. Polito states that future market prices are reliable predictors of future spot market prices and, as such, should be used in estimating avoided costs. Dr. Polito argues that future market prices: 1) accurately reflect market expectations of future supply and demand conditions; 2) reflect the expectations of the entire market; and 3) incorporate a wide range of beliefs concerning the expected future supply and demand conditions. Effectively, the forward contract prices represent a market “consensus” of future supply and demand conditions and future spot market prices. (Id. at p. 3-6 and 8.)

38. Dr. Polito asserts that Staff’s proposed “capacity credit” is inappropriate as it relies upon a hypothetical utility expansion plan rather than NPC’s actual expansion plan. The hypothetical expansion plan includes generation that NPC has no intention of constructing. Dr. Polito argues that Staff’s use of a hypothetical expansion plan rather than NPC’s actual expansion plan, which is its approved resource plan, would result in an inaccurate estimate of the costs NPC would avoid upon departure of an eligible customer. Further, Staff’s method could not be applied consistently over time. Dr. Polito explains that it is probable that some exit application will be filed at a future date wherein NPC’s approved expansion plan will contain additional generation facilities being constructed during the analysis period. (Id. at p. 18-19.)

39. Additionally, Dr. Polito states that Staff indicates that its proposal quantifies the benefits associated with either having “capacity newly available” upon the departure of the eligible customer or the delay in either the construction of generation facilities or acquisition of long-term purchased power. Dr. Polito explains that this adjustment is not necessary as PROMOD models, as firm energy, account for both avoided purchases and sales of excess

capacity (including “capacity newly available”) and energy. The eligible departing customer receives the appropriate credit for the capacity and energy it makes available to the remaining customers through PROMOD estimates. (Id. at p. 19.)

40. Regarding Staff’s argument that the capacity credit be used as a proxy for any inaccuracies in forward market prices, Dr. Polito argues that the appropriate methodology to consider potential inaccuracies in forward market prices would be to perform a sensitivity analysis on the prices, not by altering NPC’s expansion plan. Further, he notes that the potential inaccuracies explained why the “weighted average” avoided cost method is proposed, which he believes to be inappropriate. (Id. at p. 19-20.)

41. Dr. Polito asserts that Staff’s proposed load-growth credit is discriminatory as it affords the departing eligible customer a credit beyond that allocated to this customer in the PROMOD avoid cost calculation. Dr. Polito states that Staff explained that its load-growth credit assigned to the departing eligible customer the “**full benefit**” of the increase in utility revenues resulting from load growth. However, Dr. Polito argues that: 1) PROMOD’s estimated avoided costs and impact charges already considered load growth, thus any additional load growth would result in a double counting of these benefits. 2) Under the existing regulatory framework, the potential benefits associated with load growth should be assigned to all the utility customers not just the departing eligible customer and would be contrary to the public interest. 3) It is unclear if Staff’s load growth credit calculation methodology uses the benefit of load growth to offset incremental capital investment. (Id. at p. 25-26.)

42. Dr. Polito states that the avoided cost, a component of the impact or exit fee, incorporated load growth benefits and appropriately allocated the benefits between the departing eligible customer and the remaining customers. He explains that the PROMOD model dispatches a utility’s system in the least-cost manner and determines the minimum level of cost required to serve the utility’s load. One of the assumptions used in PROMOD is the utility’s load data, including load growth. Therefore, PROMOD’s calculated estimated avoided costs incorporated the benefits of any load growth. Any further credit would be discriminatory between the

departing eligible customer and the remaining customers as it “overcompensates” departing eligible customers. (Id. at p. 23-24 and Attachment at p. 25-29.)

43. Dr. Polito explains that, while load-growth increases revenues, NPC may have to make an incremental capital investment in distribution, transmission, or generation assets to serve this additional load. Any load growth benefit must be offset by any incremental capital investment NPC would be required to make to serve the additional load. (Id. at p. 21-22 and Attachment at p. 21-23.)

44. Dr. Polito also expresses concern that when the 10 percent contract provision is evaluated by Staff, Staff may attempt to classify any benefit associated with that transaction as a reduction in the exit fee. (Id. at p. 28-29.)

#### NPC’s Position

45. Mr. Pottey, NPC’s witness, asserts that, while NPC concurs that the departing eligible customer is entitled to receive consideration for any benefit that its departure brings to the remaining customers, Staff’s proposed adjustments unfairly benefit the departing eligible customer or double count the benefits PROMOD has taken into consideration in the development of the avoided costs. Staff’s adjustments were cited as a load-growth credit for the BTGR generation function component, a BTER load-growth credit, and the generation capacity credit. (Exhibit 17 at p. 5-6.)

46. Mr. Pottey states that the following difficulties exist with Staff’s proposed load-growth credit: 1) Current regulatory practice provides that the benefit of load growth between rate cases inures to the utility, which uses these revenues to fund capital expenditures required to accommodate load growth and to offset inflationary effect upon operating costs; 2) Staff has not provided a written analysis supporting its assertion that an additional credit beyond that contained in PROMOD’s avoided cost calculation is warranted; 3) Staff’s load growth calculation filed with the Commission does not contain an offset for any incremental capital investment required to serve the new load and inappropriately credits the departing eligible customer with the full benefit rather than its load ratio share. (Id. at p. 6-9.)

47. Mr. Pottey acknowledges that some level of load growth credit may be appropriate from the effective date of its next change in general rates until the end of the exit fee analysis period only if the generation related BTGR actually decreases. If the Commission were receptive to Staff's load growth credit, he recommends that the credit should be limited to the growth in generation revenues plus the decrease caused by depreciation expense and reduced by incremental generation investment and the effects of inflation on operational costs. Mr. Pottey provided an example of the revised load-growth credit calculation NPC would recommend if the Commission were to accept the load-growth credit concept. However, the example does not include the effects of inflation upon operational costs nor the required expenditures for Mohave generation facility as the amount is unknown. (Id. at p. 9-10 and Attachment CAP-2.)

48. In response to Dr. Berry's and Mr. Garrett's load growth credit statements, Mr. Pottey states that the departing eligible customer would only receive benefits after a change in the BTGR and only to the extent the generation component actually decreases. (Id. at p. 10-11.)

49. Regarding Staff's BTER load-growth credit, Mr. Pottey states that from Staff's position paper it is unclear if Staff intends to continue with its proposed BTER load growth credit. He notes, as with its BTGR load-growth credit, Staff has not provided a written rationale indicating that PROMOD does not fully consider this item. Further, Mr. Pottey asserts that the PROMOD avoided cost calculation fully considers both the costs and benefits associated with load-growth's impact upon the energy rate and that the departing eligible customer is allocated its load ratio share of this benefit. Mr. Pottey explains that the loads used in the PROMOD simulation are the hourly load forecasts for each year in the analysis, which includes the forecasted load growth. Additionally, Mr. Pottey asserts that under deferred energy accounting, Staff's BTER credit increases the remaining customers rates on a dollar for dollar basis for any BTER credit given. Further, Mr. Pottey cites Dr. Berry's statement that "The Applicants concede to Nevada Power's argument that no such credit is warranted." (Id. at p. 11-13.)

50. Mr. Pottey asserts that Staff's proposed capacity credit double counts the value of the capacity and does not reflect NPC's approved electric resource plan, which does not include

any generation capacity until 2007. Mr. Pottey explains that PROMOD avoided costs include the costs of the avoided capacity, which is purchased power, and that the PROMOD run included the revenues associated with NPC's sales of the excess capacity resulting from the eligible customer's departure, which were directly credited to that customer. Additionally, Mr. Pottey states that the avoided capacity and energy cost is equivalent to that associated with a combined cycle power plant. Further, Mr. Pottey observes that Staff's capacity credit methodology while crediting the customer with the full value of the avoided generation capacity costs ignores "the increased production costs associated with not having the new power plant available to serve load." (Id. at p. 13-15.)

51. Regarding Dr. Berry's and Mr. Garrett's support for Staff's capacity credit adjustment, Mr. Pottey reiterates his statement that no additional capacity would be avoided by an eligible customer's departure. Further, Mr. Pottey asserts that the price modeled in PROMOD represents the cost of capacity and energy NPC would have to pay in order to serve this load and the price used reflects the entire market's evaluation of price risk, which is the best indicator of future market prices. (Id. at p. 15.)

52. During Commission clarifying questioning, Mr. Pottey summarizes NPC's position that the exit fee should be the difference in lost revenue and the avoided costs associated with the departing eligible customer. The avoided costs would be the difference between a PROMOD simulation with the customer and a PROMOD simulation without the customer. Further, the avoided costs represents the "energy production cost savings, energy and capacity predominately based on the market price for energy and capacity that the Company would have to incur, but it includes ... generation...." (Tr. at p. 314.) Mr. Pottey explains that PROMOD performs a probabilistic production costing simulation that attempts to determine the least costly way to serve each hour of load. In the simulation, the inputs included all of NPC's generation and long-term purchased power and the hourly market price. PROMOD then selects the least costly manner to serve the load considering the system constraints, which could be generation or purchased power or some combination of both. (Tr. at p. 315-316.) Further, Mr. Pottey explains that Staff

inappropriately calculates its capacity credit. Staff should use the resource planning methodology to develop its credit as it considers all costs associated with building a new generation unit (e.g., capital costs, income taxes, and revenue requirements) not only production cost savings. (Tr. at p. 317-318.) Mr. Pottey has approximately ten years of experience performing PROMOD simulations, all with Sierra Pacific Power Company and, after the merger, with NPC. (Tr. at p. 315.)

53. Mr. Pottey recommends that the exit fee be based upon this revised analysis and that NPC's revised analysis provides the appropriate breakdown between BTER and BTGR impacts. The revised analysis decreases the lost BTGR revenue for the five Applicants from \$11 million to \$10.7 million and changes a loss in BTER revenues of \$6.4 million to a gain of \$0.064 million. Mr. Pottey links the significant change in BTER revenues to the termination of several high priced contracts. (Id. at p. 16-18 and Attachment CAP-3.)

54. Mr. Pottey states that, in response to Staff's request, NPC provided a revised analysis on July 1<sup>st</sup> to all the parties in this proceeding. The revised base case analysis incorporates the following: 1) fuel and purchased power costs updated as of June 20<sup>th</sup>; 2) termination of the ENRON, Reliant, Morgan Stanley and LADWP contracts; 3) addition of the Duke purchase; 4) addition of a \$1.50 per megawatt hour credit risk premium and a risk premium of \$0.15 per decatherm of natural gas; and 5) July 1<sup>st</sup> effective customer rates and revenue requirement. In addition, the high and low case scenarios were run using the revised information. (Id. at p. 16 and 18.)

55. Mr. Pottey argues that both the high and the low case scenarios should be given little or no weight. Mr. Pottey states that the base case includes market price information, which represents the entire market's evaluation of price risk and is the best indicator of future market prices. Further, NPC could lock in these prices to serve its load. Mr. Pottey contends that the high price scenario is unlikely as prices only reached this level during the late 2000 and early 2001 as a result of a combination of events (e.g., failure of deregulation in California and apparent market manipulation). Mr. Pottey contends that the probability of recurrence has been mitigated

due to increased supply, reduced demand, and the recent implementation of FERC's price cap. Mr Pottey also states that the base case market prices for peak energy already exceeded FERC's current price cap. Regarding the low price case, Mr. Pottey contends that, while the twenty years prior to late 2000 average cost of energy was lower than current levels, no indication exists that current energy prices would decline to those levels experienced prior to late 2000. (*Id.* at p. 19.)

56. Regarding Rouse's Fashion Show Mall's application, Mr. Pottey states that due to the Fashion Show Mall's current expansion it is necessary to adjust the exit fee evaluation for load growth to be experienced by Fashion Show Mall. NPC expects the load to increase to 2.5 times of the current level. (*Id.* at p. 21 and Attachment CAP-3.) Mr. Montoya recommends that the actual load forecast to be used for the Fashion Show Mall should be that provided by the Applicant's witness Mr. Gildersleeve. (Exhibit 15 at p. 13-14.) Additionally, Mr. Montoya states that, if Mr. Gildersleeve's load estimates were used to develop the exit fee, in order to protect the remaining consumers and itself, NPC would revise the Fashion Show Mall's and the Constellation Energy Central Plant current Rule number 9 contracts to reflect the projected substantial reduction in load. (*Id.* at p. 15-16.)

57. Mr. Pottey states that the MGM application was adjusted to reflect the service classification to be experienced by the Monte Carlo. Currently, the Monte Carlo and Bellagio resorts are billed as a combined entity under NPC's LGSX tariff. However, when the Bellagio departs, as part of the MGM load, the Monte Carlo would no longer qualify for service under the LGX tariff but under the LGS-3 tariff, which would increase Monte Carlo's annual cost by \$30,253. (Exhibit 17 at p. 21-22 and Attachment CAP-3.) Mr. Montoya explains that a substation owned by the Bellagio Hotel is the Monte Carlo Resort's primary source of power. If the Bellagio (i.e. MGM Mirage) and the Monte Carlo Resort are unable to resolve this issue, NPC proposes to present the Monte Carlo Resort issue, and any similar issues, to the Commission when the Distribution Service Agreement is filed. (Exhibit 15 at p. 12-13.)

58. Ms. Englin, on behalf of NPC, recommends that the present value discount rate be NPC's pretax authorized rate of return of 8.37 percent. Ms. Englin asserts that use of the pre-tax

cost of capital allows NPC to be “compensated for income taxes paid on the earnings from the lump payments and insures that the remaining customers are not charged for taxes when customer rates are reset.” Ms. Englin argues that use of a grossed up discount rate of return would shift the tax burden to NPC until rates are reset, at which time the burden would be shifted to the remaining consumer. This would violate NRS 704B.310.6. Additionally, Ms. Englin states that the pre-tax cost of capital is used for similar analyzes that are prepared in the integrated resource plan.

(Exhibit 23 at p. 2-4.)

59. Ms. Grosulak recommends that since Reliant is in the position to know the entire amount of energy revenue that it will receive from the customers, it is reasonable to have Reliant collect the continuing taxes and fees (e.g. mill assessment) from these departing eligible customers and remit them to the appropriate entity. The stipulation at paragraph 15 obligates these departing customers to comply with NAC 704B.390, which indicates that a departing customer obligated to continue to pay any fee, tax, or assessment that would be due to any governmental entity. (Exhibit 12 at p. 6-7.)

Rebuttal Position of Station Casinos, Inc.; Coast Hotels and Casinos, Inc.; Gordon Gaming Corp., d/b/a Sahara Hotel and Casino; and Rouse Fashion Show Management, LLC

60. Dr. Berry recommends that the Commission not assess an additional exit fee other than those associated with deferred energy and other potential liabilities set forth in the stipulation (e.g., QF contracts out if market costs three years after departure). (Exhibit 27 at p. 1 and Attachment DMB-2R.)

61. Dr. Berry disagrees with NPC that a capacity credit is inappropriate. The fact that the capacity costs that would be avoided are beyond Staff’s analysis period does not justify their exclusion from the determination of the exit fee. Of particular issue is the delay of the planned generation additions in 2007 until 2008 due to the departure of the eligible customers. Dr. Berry estimates an \$8,216,380 net reduction in present worth of revenue requirements associated with delaying the planned 2007 generation facilities until to 2008. Dr. Berry proposes allocating this benefit to the five applicants on the basis of peak loads. Dr. Berry argues that it is appropriate to

allocate these avoided capacity costs to the departing eligible customers because no benefit would exist unless these customers switched to a new provider. However, since his analysis demonstrates that the departure of these eligible customers would provide a net system benefit rather than a cost, the remaining customers do receive some benefits of these avoided capacity costs. (Id. at p. 2-5 and Attachment DMB-3.)

62. While not including Staff's capacity credit concept or its probabilistic approach methodology in his exit fee analysis, Dr. Berry agrees that a short-term benefit to NPC and its remaining customers exists for reduced market price risk. Using the probabilities of 10 percent, 85 percent, and 5 percent, Dr. Berry estimates the benefit for all five applicants to be in excess of \$3 million. (Id. at p. 8-9 and Attachment DMB-6.)

63. Dr. Berry concurs with Staff that a load-growth credit is appropriate. Dr. Berry asserts that load-growth credit and the benefits associated with load-growth incorporated in the base case are independent, which was supported by his recalculation of BCP's examples. Dr. Berry states that his recalculations of both lost revenues and avoided costs using BCP's Tables 4 through 6, assuming only system load growth, resulted in no increase to either component. Dr. Berry states that his calculated load-growth credit is a hybrid of Staff's and NPC's methodologies. (Id. at p. 5-8; Attachment DMB-4; and Attachment DMB-5.)

64. Dr. Berry argues that futures prices do not accurately predict future market prices. (Id. at p. 9.)

65. Dr. Berry argues that the applicants should not be subject to a revisiting of the exit evaluations after the applicant submits its official intent to proceed with their proposed transaction. He states that, if the concern were a result of NPC entering into a long-term contract before the submittal of the official notice to proceed, the stipulation provisions address this concern. The applicants have agreed to be bound by any Commission's determinations concerning that contract. (Id. at p. 9-10.)

66. Mr. Gildersleeve asserts that if NPC's tariff addresses how line extension disputes are to be addressed, then it should be handled in a proceeding apart from this one. Further, the

Rouse Company will continue to work closely with NPC to ensure that all line extension policies are adequately adhered to. Additionally, Mr. Gildersleeve provides a schedule illustrating the range of proposed exit fees. (Exhibit 26 at p. 2-3 and Attachment DJG-2R.)

MGM / Mirage's Rebuttal Position

67. Mr. Garrett asserts that the load-growth credit is justified on the basis that PROMOD only calculates the avoided variable costs and ignores the fixed costs that revert back to NPC and its remaining customers when an eligible customer departs, which are the costs the exit fee attempts to quantify. Further, if these fixed costs are paid by new customers in their BTGRs and not removed from the exit fee then NPC inappropriately double recovers the costs (i.e. exit fee and new customer BTGR revenues). Therefore, Dr. Polito's assertion that PROMOD accurately compensates the departing eligible customer is inaccurate for fixed costs. Mr. Garrett asserts that Staff's adjustment quantifies this reality. Additionally, Mr. Garrett provides a revised exit fee analysis. (Exhibit 28 at p. 2-4 and Attachment MG/Rebuttal-1.)

68. Mr. Garrett argues that it is inappropriate to allow NPC to rely upon regulatory lag as a reason to charge a departing eligible customer an increased exit fee. Mr. Garrett states that Mr. Pottey's contention that the traditional ratemaking formula allows NPC to retain excess earnings associated with load growth between rate cases is not necessarily true in the state of Nevada. Mr. Garrett states that due to deferred energy accounting any excess earnings an electric utility earns between rate cases would be credited against the utility's deferred energy account balances in the utility's deferred energy case. Since the Applicants are required to pay their entire share of the deferred energy balances accumulated at the time of their departure, these customers are precluded from sharing in any subsequent reduction in deferred accounts that may occur from excess earnings. (Id. at p. 3-4.)

69. Mr. Garrett argues that, as recognized by Staff since the beginning of this process, upon departure of an eligible customer NPC would experience less market price risk, as it would obtain a greater portion of its power requirements from its own generation. Unless this benefit is considered in the exit fee the benefit would inure to NPC and the remaining customers and not to

the departing eligible customer whose action gave rise to the benefit. Mr. Garrett calculates the benefit by weighting the low, base, and high cases with the following probability percentages: 1.5, 97.0, and 1.5 percent. Mr. Garrett argues that the weighting recognized that the purchase power market liquidity had declined due to the suspension of electricity trading by NYMEX and the exit of both ENRON and Dynegy, two of the largest traders, from the business. (Id. at p. 5-7.)

#### Commission Discussion and Findings

70. The Commission finds that Staff's rationale for limiting its analysis in this proceeding to three years, particularly in light of the terms of the Stipulations, is reasonable and hereby accepted.

71. The Commission finds that the Stipulations are in the public interest and directs the Parties to comply with the terms and conditions of those Stipulations.

72. The Commission concludes that the Stipulations should be approved.

73. While the Parties propose additional concepts to be addressed, no Party takes exception to the use of PROMOD as the primary tool to develop the avoided costs associated with the departure of an eligible customer. Therefore, the Commission finds that the use of PROMOD to develop the avoided costs associated with the departure of an eligible customer is reasonable and approved.

74. On the issue of the Applicant's entitlement to future changes on the system once they depart, NPC is correct to the extent that should any load-growth benefit exist, it would not occur until the next change in the BTGR. Due to the lack of any other information, the next general rate change is expected to be (NRS 704.110(3) March 31, 2004. Thus, any change would be in effect from March 31, 2004, through the end of the analysis period, December 31, 2005. Staff states that any load-growth credit would be less than three percent of the lost revenues. Since any load-growth benefit would not occur until later in the analysis period one would expect any benefit in total to be less than three percent on a nominal basis and significantly less on a present value basis. Therefore, the Commission finds that any load-growth benefit would be insignificant.

75. In the establishment of a discount rate, Staff recommends that the Commission take the consumer's point of view and utilize a federal income tax grossed up discount rate of 11.44 percent. NPC recommends that the Commission use its last authorized rate of return in order to prevent it or its remaining customers from paying the federal income taxes associated with the exit fee. Further, NPC states that the development of the exit fee is more akin to the resource plan financial analysis than a ratemaking proceeding and that the last authorized rate of return was used as the discount rate in the resource planning process. The Commission is persuaded by NPC arguments that the discount rate should be NPC's last authorized rate of return and therefore finds the discount rate should be 8.37 percent.

76. Except for Rouse, Staff recommends that the Applicants not be charged an exit fee other than their load ratio share of the deferred energy account balance. But for Staff forcing its results to zero, Staff's analysis would require the remaining customers to pay the departing eligible customers a fee for leaving NPC's system to take power from a new provider.

77. In its probability analysis, Staff opines that for both the low case and the high case the probabilities range from 4 percent to 10 percent and Staff assigns 10 percent probability to both cases. However, Staff does not justify why it selects the high end of its probability range. Additionally, Staff applies its probability analysis on an asymmetric basis. Staff performs a sensitivity analysis associated with the avoided cost calculation but fails to apply a similar analysis to the estimated lost revenues.

78. Like Staff, Dr. Berry's recommendation is based in part upon an asymmetric analysis. While Dr. Berry calculates a capacity credit for the forecasted one-year delay in the construction of generation facilities from 2007 to 2008, Dr. Berry fails to modify his lost revenue estimate.

79. Incorporation of Staff's and the customers' capacity credit leads to use of a "hypothetical expansion plan", as indicated by Dr. Polito, and necessarily creates a methodology that is difficult to apply consistently in future cases.

80. In addition to the foregoing, NPC's PROMOD simulation expertise should be

afforded some consideration in this matter. NPC provides a cogent explanation of how PROMOD incorporates existing generation into the development of the least cost manner of operating NPC's system. Further, Mr. Pottey explains how the departure of an eligible customer would affect NPC's system costs, the avoided costs used in the exit fee calculation. Based upon this explanation, with consideration of NPC's PROMOD simulation expertise, the Commission concurs with NPC that Staff's capacity credit double counts the benefit associated with the capacity made available by the departure of the eligible customer. Therefore, the Commission finds that a capacity credit shall not be used in the development of an exit fee in this proceeding.

81. Additionally, the Commission is concerned that little consideration is given to potential variability in both the revenue loss and cost savings estimates. If the actual results cause a widening of the loss, the addition of a capacity credit would only serve to exacerbate the loss to NPC and remaining customers.

82. The question is whether or not benefits accruing to the system inure to the remaining customers or the departing customers. Staff and the exiting customers assign those benefits to the departing customers. However, these benefits are not tangible at the time of the actual departure of the eligible customer; rather, they accrue over time. In order to accept the analysis of Staff and the exiting customers, the Commission would have to believe that, although the eligible customers are no longer on the system, they nevertheless retain an interest in the system they left. The Commission surely cannot accept this as a reasonable result. Once a customer makes the decision to leave, presumably based on an economic analysis of the benefits or detriments at the time of departure, there is simply no basis for the customers to expect a continuing interest in the remaining system. Accordingly, the Commission finds that the approach taken by both NPC and BCP is reasonable. The result is that exit payments are due to NPC on behalf of the remaining ratepayers in the amounts indicated in the following table, which were obtained from Exhibit 25:

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Rouse Fashion Show Mall Management, LLC	\$439,000
Coast Hotels and Casino's, Inc.	\$305,000
Station Casino's, Inc.	\$1,349,000
Sahara Hotel and Casino	\$114,000
MGM-Mirage	\$1,970,000
Total	\$4,177,000

83. Further, the Commission finds it unrealistic to require the Parties to revisit the exit fee analysis after the filing had been made. However, if a significant change occurs due to an unforeseen variable one of the Parties may petition the Commission to update the results.

84. The Commission concurs with Staff and NPC that the new provider, in this instance Reliant, should be assigned the obligation to collect and remit the appropriate fees, taxes and assessments, including mill assessments. Staff's proposed language, as set forth in its Brief is appropriate. Therefore, the Commission directs Reliant, as the New Provider and to the extent it sells retail electricity and ancillary services in Nevada, report to each appropriate government agency on a quarterly basis, no later than 30 days after the end of each calendar quarter and in a form satisfactory to the agencies, all payments due from its retail customer in Nevada for that quarter. Reliant shall submit with each quarterly report that appropriate payment due to that agency in lieu of what the agency would have received from the franchised incumbent utility providing bundled service. Failure to furnish the required reports and/or payment shall be grounds for the Commission to suspend or revoke Reliant's authority as a new resource provider in Nevada.

85. In order to ensure that the affected agencies retain the same auditing authority that may currently exist, Reliant's authority as a New Provider shall be further conditioned upon allowing the appropriate governmental agency receiving payments from it, in lieu of the utility, to have access to its books and records that is comparable to what these governmental agencies

currently have to the utility's books and records in order to verify the accuracy of the payments and reports.

THEREFORE, based on the foregoing findings of fact and conclusions of law, it is hereby ORDERED that:

1. The Stipulations attached hereto as Attachment 1 and entered into by Rouse Fashion Show Management, LLC; Coast Hotels and Casinos, Inc.; Station Casinos, Inc.; Gordon Gaming Corp., d/b/a Sahara Hotel and Casino; MGM Mirage; Regulatory Operations Staff of the Public Utilities Commission; the Attorney General's Bureau of Consumer Protection; Reliant Energy Services; and Nevada Independent Energy Coalition are APPROVED as FILED.

2. Except as specifically set forth herein, the Commission's approval of these Stipulations does not constitute approval of, or precedent regarding, any legal or factual issue in this proceeding.

3. The applications of Rouse Fashion Show Management, LLC; Coast Hotels and Casinos, Inc.; Station Casinos Inc.; Gordon Gaming Corp., d/b/a Sahara Hotel and Casino; and MGM Mirage are APPROVED pursuant to the Commission Discussion above, including but not limited to, provisions of paragraphs 71, 74, 75, 80, 82, 83, 84 and 85.

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4. 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,

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DONALD L. SODERBERG, Chairman

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ADRIANA ESCOBAR CHANOS, Commissioner  
and Presiding Officer

Attest: \_\_\_\_\_  
CRYSTAL JACKSON, Commission Secretary

Dated: Carson City, Nevada

7-31-02  
(SEAL)

# ATTACHMENT 1

**Due to the voluminous nature of Attachment 1, the Stipulations are not included with Copies of this Order. Attachment 1, in its entirety, is attached to the Original Order on file with the Commission. Copies of Attachment 1 may be obtained by contacting the Commission Secretary.**