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STATE OF NEVADA

PUBLIC UTILITIES COMMISSION

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Commissioner

DAVID NOBLE
Commissioner

STEPHANIE MULLEN
Executive Director

August 18, 2015

Trisha Osborne, Assistant Commission Secretary
PUBLIC UTILITIES COMMISSION OF NEVADA
1150 East William Street
Carson City, NV 89703

RE: <u>Docket No. 15-05017 – Staff's Final Impact Analysis</u>

Dear Ms. Osborne:

Please find attached hereto for filing the Regulatory Operations Staff's ("Staff") Finalized Analysis in the above-referenced Docket.

If you have any questions, please contact me directly.

Sincerely,

Samuel Crano
Assistant Staff Counsel

SC/tmr
Attachments

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PROOF OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties of record in this proceeding by electronic mail to the recipient's current electronic mail address properly addressed to:

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DATED at Carson City, Nevada, on the 18th day of August, 2015.

Tia Roberts

An employee of the Public Utilities Commission of Nevada

STAFF'S FINAL IMPACT ANALYSIS

MGM RESORTS INTERNATIONAL'S ("MGM") NRS 704B APPLICATION

DOCKET NO. 15-05017

SUMMARY

The total load that MGM proposes to move from bundled retail electric service represents approximately 4.86 percent, over a 6-year period, of Nevada Power Company's d/b/a NV Energy's ("NPC") annual energy sales, and therefore, materially impacts NPC's future revenue and increases costs to remaining NPC customers. Based upon the calculations and production cost simulations that the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission") requested from NPC and with certain modifications that Staff is proposing thereto, Staff's final analysis of the impact of MGM's proposed departure of 59 accounts at the 19 premises identified in Amended Exhibit B to MGM's Application and corresponding coincident peak load of approximately 174 mega-watts ("MW"), utilizing the non-lump sum impact analysis or non-bypassable rate methodology, is approximately $**89.222 million.**[1,2] Table 1 provides a summary of the unmodified impact fee analyses performed by NPC under Staff's direction for both the lump sum and non-lump sum 704B Impact Methodologies.[3]

Table 1 – Summary of MGM's Unmodified Impact Fees by Analysis Period[4]			
Analysis Period	Impact Fee ($ in millions)	Net Present Value of Impact Fee ($ in millions)[5]	Percentage of NPC's annual energy sales
Lump Sum704B Impact Methodology			
3-year	$120.677	$108.008	4.94
6-year	$190.899	$155.236	4.86
10-year	$245.420	$181.973	4.68
Non-Bypassable Rate 704B Impact Methodology			
3-year	$69.511	$63.320	4.94
6-year	$115.322	$96.334	4.86
10-year	$142.765	$111.505	4.68

1 With the use of a non-bypassable rate methodology, there is no need to provide an estimated amount of renewable portfolio energy credits ("PECs") that the MGM should be allowed to take with them, since the actual amount of PECs MGM should be entitled to will be calculated as part of the non-bypassable rate components.

2 Under the non-bypassable rate methodology, the $89.222 million impact fee is assessed to MGM as a lump sum payment upon MGM departing NPC's bundled retail electric service. After MGM's departure, MGM will also pay the non-bypassable charges via NPC's distribution only service tariff.

3 Staff requested 3, 6 and 10- year analyses be performed with and without the concept of non-bypassable rates for certain cost components outlined by the Commission in its Order in Docket No. 14-11007. Staff has not made any modifications to the amounts listed in Table 1. Staff's adjustments were only calculated for the 6-year non-bypassable rate analysis since that is the methodology Staff is utilizing in its impact analysis.

4 The lump sum 704B Impact Methodology figures provided by NPC do not include the annual $8 million in renewable costs associated with executed PEC only contracts, and therefore, the impact fees listed in Table 1 are slightly understated. This omission does not impact the non-bypassable rate impact fees, since the cost of the PEC only contracts would be recovered along with the cost of other standard renewable energy contracts via the non-bypassable rate components.

5 The net present value impact fees listed in Table 1 include the 5 percent local government fee.

The Final Impact Analysis provides the procedural background for Staff's analysis, and pursuant to Nevada Administrative Code ("NAC") 704B.350 (7), provides a description of the methodology, assumptions, sources of information and other information Staff utilized to estimate the potential impacts of MGM's proposed departure from NPC's bundled retail electric service.

As is outlined below, Staff's calculated impact fee provides a reasonable balance between protecting remaining customers from increased costs and ensuring 704B Applicants do not pay more than they should to depart NPC's bundled retail electric service. However, should 704B Applicants argue for additional credits and other cost reducing assumptions in their Alternative Analyses (thereby skewing the balance Staff strove to find), Staff may make additional recommendations or modifications in response to potentially recapture that balance and to protect ratepayers once it reviews the various Alternative Analyses.

BACKGROUND

On May 22, 2015, Staff directed NPC, pursuant to Nevada Administrative Code ("NAC") 704B.350 to perform a set of production cost simulations and rate calculations in order to determine the impact that the departure of MGM's load would have on remaining customers as well on NPC utilizing the lump sum 704B impact methodology. Thereafter, on July 10, 2015, following an analysis of the Order in Docket No. 14-11007, the discussions occurring in Docket No. 15-06015 and Procedural Order No. 1 issued on July 8, 2015, in Docket No. 15-05017, Staff further directed NPC to perform two additional separate analyses to determine the impact that a departure of Las Vegas Sands Corp's, Wynn Las Vegas', and MGM's (collectively referred to as "the Applicants") aggregated loads would have on remaining customers as well as on NPC; a lump sum 704B impact calculation and a 704B impact calculation utilizing non-bypassable rates. A copy of Staff's directions to NPC is provided in Attachment 1. Attachment 1 lays out the key inputs and analysis criteria NPC was to use in performing the calculations and production cost simulations. On July 28, 2015, NPC provided Staff with a copy of the requested calculations and output reports from the production cost simulations ("Requested Calculations"). Staff has reviewed the Requested Calculations, and found the Requested Calculations to be consistent with the directions that were given to NPC (per Attachment 1). Additionally, Staff provided MGM with a copy of its preliminary analysis on August 4, 2015, and met with the MGM to discuss the preliminary analysis on August 7, 2015. With certain proposed modifications summarized below, Staff believes that the Requested Calculations are a reasonable estimate of the impact of MGM's departure would have on remaining customers and NPC pursuant to the provisions of Nevada Revised Statutes ("NRS") Chapter 704B.

REQUESTED CALCULATIONS

704B Impact Methodology Calculation Utilizing Non-Bypassable Rates

In Docket No. 14-11007, the Commission found that Switch's Amended Exit Application was contrary to the public interest because it would have resulted in increased costs to NPC's remaining customers and, therefore, denied Switch's Amended Exit Application.[6] Specifically, the Commission had a concern that it would be contrary to the public interest to allow Switch to exit NPC's bundled electrical retail service and circumvent paying its share of the costs incurred by NPC to comply with Nevada's legislative energy policies.[7] As a result of the questions the Commission raised in Docket Nos. 14-11007 and 15-06015, Staff believes the cost components associated with NPC's compliance with Nevada's legislative energy policies as follows: the REPR, TRED, EE program and implementation costs, long-term must take renewable energy resource contracts required by the RPS Standard, and Senate Bill ("SB") 123 costs, including, but not limited to decommissioning and site remediation costs.[8]

As a result of the Commission's Order in Docket No. 14-11007 and the discussions occurring in Docket No. 15-06015, Staff directed NPC to perform additional analyses utilizing the concept of non-bypassable rates to address the Commission's concerns regarding the costs associated with NPC's compliance with Nevada's legislative energy policies. In its July 10, 2015, Directive to NPC, Staff outlined the methodology to calculate the MGM's impact fee utilizing non-bypassable rates. Staff directed NPC to perform the lump sum analyses consisting of the BTGR rate and the BTER/PROMOD analyses. The results of the lump sum 704B impact analyses become the starting point of the non-bypassable rate analyses. Once the BTER impact fee is calculated under the lump sum methodology, the next step is to calculate the portion of the BTER impact fee attributed to the out-of-the money costs of the long-term must-take renewable energy contracts required by Nevada's RPS Standard (referred to as the "R-BTER"). The R-BTER costs are calculated by substituting NPC's average monthly system costs for the contractual prices for each of the out-of-the money long-term must-take renewable energy contracts and subtracting that cost from the actual costs of the same renewable energy contracts.[9] The R-BTER costs are then subtracted from the BTER impact fee to determine MGM's "net BTER" impact fee. Staff directed NPC to not include any costs associated with the Merrill Lynch regulatory asset, the REPR, TRED, or any costs associated with SB 123; as those costs will be recovered through the non-bypassable rate.[10]

The Requested Calculations utilizing the non-bypassable rate methodology for a 6-year term show impacts of MGM's load departing to be, without Staff's modifications, approximately $115.322 million, with a net present value of $96.334 million; compared to $190.899 (with a net

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6 Paragraph 124, page 59, of the Commission's Order in Docket No. 14-11007, dated May 5, 2015.

7 *Id.* at Paragraph 126.

8 *Id.*

9 A capacity component was included in the calculation for the months of July, August and September and was set at the forecasted market capacity price.

10 The R-BTER calculated in Staff's non-bypassable impact fee provides an estimation of the costs associated with the out-out-the money renewable energy contracts. It is not the actual R-BTER that will be assessed to 704B Applicants once they depart NPC's bundled retail electric service. Additionally, Staff believes that the non-bypassable rate assessed under a DOS tariff may need a clearing rate or other mechanism to true up costs.

present value of $155.236) under a 6-year lump sum impact fee.[11] Staff's Final Impact Analysis utilized a 6-year analysis period. Staff believes the 6-year period is appropriate as it allows two full integrated resource planning cycles for NPC to modify its electric operations as a result of MGM's departure, thereby minimizing any future stranded cost impacts associated with the MGM's departing load. Furthermore, the 6-year analysis period is a reasonable time period to forecast and analyze energy market conditions and also allows for the conclusion of the vast majority of the remaining contract terms on NPC's three remaining long-term Qualifying Facility ("QF") contracts, thereby alleviating the need to include the these legislatively mandated out-of-the-money QF contracts to be also included in a non-by-passable rate.[12] The summary sheets from the Requested Calculation are attached hereto as Attachment 2 and the seven separate categories that make up the estimated impact fee are: 1) BTGR, 2) "net BTER", 3) ERCR Approved Self Build 15 MW Generation – 2016, 4) ERCR Approved Bundled 274 MW Generation – 2015, 5) ERCR Approved 222MW SunPeak Acquisition - 2015, 6) acquisition of the 25 percent share of the Silverhawk Generating Station – 2017, and 7) Local Government Fees.

1) BTGR Impact: This is the base tariff general rate ("BTGR") revenue impact that NPC will experience, and remaining customers will be burdened with, once MGM's load leaves bundled retail service. Upon departure, MGM will pay only transmission (pursuant to NPC's Open Access Transmission Tariff, ("OATT")) and distribution charges (pursuant to NPC's Distribution Only Service ("DOS") Tariff).

The BTGR portion of MGM's 6-year impact fee is $87.288 million, with a net present value of $67.520 million. Staff believes this impact would accrue to NPC and/or remaining customers as a result of MGM's departure. This impact is caused by NPC receiving less revenue from MGM over the 6-year timeframe. The reduction in revenue is mainly the result of MGM no longer paying for generation assets that were built, in part, to serve its load, such as the $750 million Harry Allen combined cycle unit which was placed into service in 2011. Up until the time of the next general rate case ("GRC") filing (after the MGM's departure) the costs associated with the BTGR impact would be borne by NPC's shareholders, however, when rates are reset in NPC's next GRC with MGM's no longer being a full requirements bundled customer, the BTGR impact would become a cost borne by remaining customers.

2) Net BTER Impact: This is the estimated impact that will result to fuel and purchased power costs as a result of MGM's load being removed from the total load that NPC is required to serve. The base tariff energy rate ("BTER") Impact was determined by performing two production cost simulations: one simulation with the Applicants' aggregated load in the load forecast ("Base

11 The approximately $59 million difference between the 6-year lump sum impact fee and the 6-year non-bypassable rate impact fee provides a rough estimate of MGM's load energy ratio share of Nevada's legislated energy policies using Staff's costs and assumptions used in its 704B lump sum impact fee analyses.

12 Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), electric utilities are required to purchase energy and capacity from qualifying small power production facilities and cogeneration facilities at either the utility's avoided cost or at a negotiated rate.

Case") and one with the Applicants' aggregated load removed ("Change Case").[13] Staff's BTER impact analyses excluded all of the placeholder resources contained in NPC's currently filed Integrated Resource Plan ("IRP") filing,[14] Docket No. 15-07004, in the PROMOD production cost simulation and assumed all energy and capacity needs were met with market purchases. The difference in the production costs between the Base Case and the Change Case is the BTER impact resulting from the Applicants' aggregated load departing NPC's bundled retail service. The BTER impact fee associated with the aggregated load production cost simulation was allocated to MGM based upon its annual energy load ratio share. MGM's energy load ratio share of the Applicants' aggregated Net BTER impact fee is $17.875 million, with a net present value of $16.411 million.

Staff has performed a review of the production cost simulations and believes the increase in the average system costs (in the early years of the analysis) is attributable to generation dispatch changes: Because MGM's load has a higher than average load factor, MGM's load allows NPC to economically operate its low-cost combined cycle units in the evening and shoulder/winter periods. Running these low-cost combined cycle units helps offset the higher cost of renewable resources and brings the average system cost down. When MGM's load departs, the capacity factors for the low-cost combined cycle units (mainly Higgins, Lenzie and Silverhawk) drops, thereby increasing the average system cost.

3) ERCR Approved Self Build 15 MW Generation – 2016: This cost represents MGM's load ratio share of this generation asset that was approved while MGM was a customer.

4) ERCR Approved Bundled 274 MW Generation – 2015: This cost represents MGM's load ratio share of this generation asset that was approved while MGM was a customer.

5) ERCR Approved 222MW SunPeak Acquisition – 2015: This cost represents MGM's load ratio share of this generation asset that was approved while MGM was a customer.

6) Acquisition of the 25 percent share of the Silverhawk Generating Station – 2017: This cost represents MGM's load ratio share of the acquisition price ($77.0 million) of the 25 percent share of the Silverhawk Generating Station NPC is requesting Commission resource planning approval to acquire in Docket No. 15-07004. Staff believes it is appropriate to include the cost of this acquisition, since it was negotiated and executed before MGM would depart NPC's bundled retail service. Additionally, Staff's recommendation in Docket No. 15-07004 will likely be that the Silverhawk acquisition satisfies the remaining 54 MW of planning capacity mandated by SB 123.

Furthermore, Staff's use of the acquisition price of $77 million for the 25% share of the Silverhawk Generating Station is conservative. NPC is forecasting approximately $61 million in

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[13] Each set of production cost simulations was performed twice – one with the external off-system sales function turned off and once with the external off-system sales function turned on. The increased benefit associated with NPC making increased off-system sales as a result of MGM's load departing bundled retail service was then determined and MGM was given credit in the BTER calculation for 50 percent of this forecasted sales revenue.

[14] Although NPC's IRP filing in Docket No. 15-07004 excluded Switch's load, the MGM impact analysis includes switches load.

capital additions for the Silverhawk Generating Station in the next ten years in its Fall 2014 Business Plan for the Silverhawk Generating Station. Attachment 3, Staff data request 31 in Docket No. 15-07004, provides NPC's projected capital expenditures for the Silverhawk Generating Station over the next ten years. Currently, NPC's co-owner of the Silverhawk Generating Station, the Southern Nevada Water Authority, pays its share of the capital additions associated with maintaining the Silverhawk facility. Since NPC is acquiring Southern Nevada Water Authority's 25% share of Silverhawk, NPC's ratepayers will pay all of the costs associated with these future capital additions but because of uncertainties in the timing of when these capital expenditures could occur and the actual cost of these expenditures, Staff did not include this incremental cost in the MGM's 704B impact fee calculation.[15]

7) Local Government Fees: This cost represents the 5 percent Franchise Fee Clark County mandates that NPC collect on revenue generated in Clark County. This cost is much like a sales tax, and is derived by simply multiplying the sum of the other cost categories by 5 percent. This fee would be payable to Clark County. Additionally, MGM, or its provider of new electric resource, will still be required to pay Mill tax (to the Commission) via all sales made by its provider of new electric resource.

STAFF'S PROPOSED MODIFICATIONS

After reviewing the Requested Calculation, underlying data and production cost simulations, Staff believes that some adjustments need to be made to the figures provided by NPC. With Staff's adjustments, MGM's 6-year impact fee is $89.222 million; which if not assessed to MGM upon MGM's departure; it would eventually increase NPC's remaining residential customers' rates by approximately $6.1 million per year.[16] Similarly, under the lump sum methodology, if the 6-year lump sum impact fee of approximately $155.236 was not assessed to MGM upon MGM's departure; it would eventually increase NPC's remaining residential customers' rates by approximately $10.6 million per year. The following is a summary of each proposed adjustment.

1) Variable Operations & Maintenance ("O&M") Costs: As discussed above, once MGM's loads depart bundled retail service, NPC's generation units will operate less, and will therefore incur lower variable O&M costs, such as chemicals and other consumables. Because variable O&M costs are included in the BTGR rate and not in the BTER rate, MGM is paying for a fixed amount of variable O&M costs in the exit fee calculation, and therefore should be given credit for the reduction in variable O&M costs that incur when MGM's loads are removed. Based upon production cost information provided by NPC from the requested PROMOD runs, Staff has estimated the O&M credit to be approximately $8.792 million. The workpapers associated with

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[15] It may be appropriate to allocate to MGM its share of the incremental costs associated with the capital additions at the Silverhawk Generating Station.

[16] See Attachment 9 for an example of the estimated breakdown of the increased costs of MGM's 6-year non-bypassable rate impact fee or MGM's 6 year lump sum impact fee, if not assessed to MGM upon departure, to NPC's remaining customers, allocated to the RS, LGS2-S, and LGS-3P rate classes.

this adjustment are provided in Attachment 4. The amount should be deducted from the BTGR Impact since O&M costs are collected through BTGR rates.[17]

2) DSM Recapture: The demand side management incentives ("DSM") that were provided by NPC to MGM over the past 5 years and the associated implementation costs should be refunded to NPC, based upon the remaining program life associated with each incentive, and included in the impact fee calculation, should MGM choose to depart retail service under the provisions of NRS 704B. Staff has calculated the repayment of the prorated DSM incentives and associated implementation costs to be approximately $3.226 million. This amount should be added to MGM's impact fee as a separate line item. The workpapers associated with the DSM recapture payment are provided in Attachment 5.[18]

3) Energy Efficiency: This is the cost associated with operating the demand side management ("DSM") programs that have been approved by the Commission as well as any financial disincentive due to the DSM programs. The Stipulation filed in Docket No.15-02039 includes the 2015 DSM program and implementation (financial disincentive) rates. DSM program and implementation rates will go into effect on October 1, 2015, prior to MGM departing NPC's bundled retail service. Should MGM choose to depart NPC's bundled retail service under the provisions of NRS 704B, remaining ratepayers would be subjected to increased costs due to NPC not recovering MGM's share of the energy efficiency program and implementation costs. Therefore, Staff is including MGM's share of the proposed energy efficiency program and implementation costs for the time period of February 1, 2016, to September 30, 2016, as a lump sum payment. Staff has estimated the EE lump sum payment to be approximately $1.302 million. The workpapers associated with this adjustment are provided in Attachment 6. The rates set in 2016, and in following years, will not be applicable to MGM as they will no longer be a customer of NPC and not eligible to participate in DSM Programs. Therefore, Staff believes MGM should not be assessed any energy efficiency costs in the non-bypassable rate.

4) Correction to the GS and LGS-1 Revenue Calculation: Staff discovered a small error in the impact calculation regarding the revenues associated with MGM's GS and LGS-1 loads. The billing determinants used in the calculation of MGM's GS and LGS-1 loads are incorrectly segregated into time of use periods. MGM's GS and LGS-1 loads do not utilize time of use rates, and therefore, the calculation is incorrect. This correction increases the BTGR impact by $973,000 over the 6-year analysis period. The workpapers associated with this adjustment are provided in Attachment 7.

5) Correction to the LRS2-3T and LRS3-XP Revenue Calculation: After receiving Staff's preliminary analysis, MGM discovered a small error in the impact calculation regarding the revenues associated with MGM's LSR2-3T and LRS3-XP loads. The impact calculation used the incorrect Customer Specific Facilities Charges in calculating the DOS revenues received

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[17] Consistent with what was done with respect to giving MGM credit for 50 percent of forecasted off-system sales revenue, Staff's Variable O&M credit is an average of the reduced variable O&M cost between the sales and non-sales production cost simulations

[18] Staff believes the repayment of DSM incentive costs provides a better mechanism to protect remaining customers, than to continue to charge departing customers an ongoing energy efficiency rate.

from MGM's LSR2-3T and LRS3-XP loads. This correction decreases the BTGR impact by $5.28 million over the 6-year analysis period. The workpapers associated with this adjustment are provided in Attachment 8.

VI. SUMMARY

Total Impact Fee per Requested Calculation	$115.322 million
Staff's Variable O&M Credit(BTGR)	($8.792 million)
Staff's DSM Recapture	$3.226 million
Staff's Energy Efficiency Adjustment	$1.302 million
Staff's Correction to the GS and LGS-1 Revenue Calculation	$0.973 million
Staff's Correction to the LRS2-3T and LRS3-XP Revenue Calculation	($5.28 million)
Total Impact Fee	**$106.751 million**
Net Present Value of Impact Fee (8.09% discount rate) [19]	**$84.974 million**
Local Government Fee (5%)	**$4.249 million**
Staff's Final MGM Impact Analysis Fee	**$89.222 million**

[19] When determining the NPV figure, Staff used the same overall present value factor NPC used in the Requested Calculation. That factor was 79.6 percent (i.e., ratio of Requested Calculation present value impact to Requested Calculation total impact).

ATTACHMENT 1

DIRECTIVE DOCUMENT

STAFF's NRS 704B Combined Exit Impact Analysis

Docket Nos. 15-05002, 15-05006, and 15-05017 – "Las Vegas Sands Corp" ("LVSC"), "Wynn Las Vegas" ("Wynn"), "MGM Resorts International" ("MGM")

As required by Nevada Administrative Code ("NAC") 704B.350 and pursuant to Procedural Order No. 1 issued on July 8, 2015, in the above aforementioned dockets, Staff is requesting Nevada Power Company d/b/a NV Energy ("NPC") perform the following calculations/PROMOD analyses in order for Staff to estimate the potential impacts of Sands', Wynn's, and MGM's (collectively referred to as "the Applicants") aggregated loads exit on the electric utility and remaining customers. The analysis is divided into two categories: 1) the BTER/PROMOD impacts analysis; and 2) the BTGR rate analysis. The key inputs and assumptions that Staff is requesting be used for each category are described herein below. Additionally, given the discussions that occurred in Docket Nos. 14-11007 and 15-06015 regarding the use of non-bypassable rates for certain costs items, Staff is requesting an additional set of analyses that utilize the concept of non-bypassable rates. If NPC has any questions regarding its requested analyses, please contact Staff immediately. Please provide the results of these analyses on or before July 28, 2015. When the results are provided all work papers should be included, including work papers showing the yearly capacity credits that were given as a result of the combined load departing, the variable operation and maintenance savings NPC will accrue as a result of the combined load departing and NPC's generation units operating potentially less. Additionally, please provide copies of the PROMOD output files generated in performing these analyses.

<u>ANALYSES #1 – TRADITIONAL IMPACT METHODOLOGY</u>

<u>BTER/PROMOD ANALYSIS</u>

- Use NPC's PROMOD software to perform ten-year production cost simulations, with takeoff points at years three, six and ten.
- Perform two sets of production cost simulations: a) Base Case Expansion Plan; and b) Exit Impacts or "change case" Plan.
- Base Case Expansion Plan
    - o Use the NPC's preferred plan, Case B, in Docket No. 15-07004, NPC's triennial integrated resource plan ("IRP"),[1] as the base case expansion plan:

[1] Application of Nevada Power Company d/b/a NV Energy seeking approval of the 2016-2035 integrated resource plan, its three year Action Plan for 2016-2018, which include a pilot subscription solar program, the acquisition of a 25 percent share of the Silverhawk Generating Station and reliance on market purchases to meet its remaining near-term open position.

        - Include the acquisition of the 25% share of the Silverhawk Generating Station on May 1, 2017, for $77 million.
        - **<u>Exclude</u>** the 5 MW solar PV resource associated with the Subscription Solar pilot program, with an in-service date of December 1, 2016
        - **<u>Exclude</u>** all of the resource additions not specifically seeking resource plan approval (i.e., all placeholder resources) including, but not limited to:
            - 706 MW 2x1 Combined Cycle placeholder in 2020
            - Two 93 MW Combustion Turbines placeholder in 2022
            - 706 MW 2x1 Combined Cycle placeholder in 2023
            - 54 MW resource placeholder in 2018
            - 100 MW solar PV resource with an in-service date of December 1, 2017
            - 10 MW solar PV resource with and in-service date of December 1, 2017
            - 10 MW solar PV resource with and in-service date of December 1, 2018
            - 10 MW solar PV resource with and in-service date of December 1, 2021
    - Use the base load forecast contained within NPC's IRP filing (Docket No. 15-07004), and add to the base load forecast Switch's hourly load as contained in Staff's Final Impact Analysis, Exhibit 5 in Docket No. 14-11007. In short, put Switch's load back into the load forecast for the purpose of these analyses.
    - Use the base fuel and purchase power forecast with the Clean Power Plan carbon Assumption contained in NPC's IRP filing (Docket No. 15-07004).
    - Assume all energy and capacity needs associated with resources excluded above are fulfilled with market purchases at the prices contained in the fuel and purchase power forecast discussed above.
- Change Case Plan
    - The load forecast for the Change Case Plan is the Base Case plan load forecast with the Applicants' aggregated load removed. Use LVSC's, Wynn's, and MGM's actual billing determinates during the 12-month period April 2014 through March 2015 for each of the service locations identified in Exhibit 1 of LVSC's Exit Application, Exhibit 1 of Wynn's Exit Application, and Revised Exhibit B of MGM's Exit Application as LVSC's, Wynn's, and MGM's ten-year load forecast, respectively, with the following clarifications:
        - MGM Properties 1 and 12 are served from the same substation but are separate premises.[2]

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[2] This was a potential error in the preliminary analysis numbers that were provided to Staff in Docket No. 15-05017 and that was discussed with NV Energy at the July 8, 2015, preliminary analysis meeting.

        - Shape the output of the MGM owned 6.4 MW solar photovoltaic ("PV") system located and operating at the Mandalay Bay for all 8760 hours in the year and include the shaped output as an offset to the Mandalay Bay's billing determinates, but do not include any other planned or under construction solar PV systems or planned demand additions.[3]
        - Offset the output of the MGM's owned combined heat and power ("CHP") generating facility, located at the Aria, from the Aria's billing determinants.[4]
    - Because PROMOD only dispatches on a whole MW basis, the aggregated load needs to be rounded to the nearest MW. The use of the 12 month period ending March 2015 incorporates demand side management programs implemented, to date, by the Applicants.
    - Use February 1, 2016, as the Departure Date for the analyses. The ten-year analysis period is therefore February 1, 2016, to January 31, 2026.
- Both the Base Case Expansion Plan and Exit Impacts Plan
    - The production costs simulations should be performed under two different scenarios: i) with external sales turned off; and then ii) with external sales turned on. Staff believes, at this time, that the exiting applicants should be credited with 50 percent of the PROMOD forecasted off-system sales and should be included in the overall analysis.
    - Since it is not yet known what LVSC's, Wynn's, or MGM's contract is or whether NPC will decide to accept the 10 percent contract that must be offered pursuant to NAC 704B.360, do not include the 10 percent contract in either Plan.
    - Assume renewable portfolio compliance is, and shall be, met by NPC without additional borrowing from Sierra Pacific Power Company ("SPPC").[5]
    - Assume no physical transmission constraints that would prevent each Applicant from being granted its full requested transmission import rights at the Mead 230 kV interconnection point.
    - Allocate any annual BTER impact fees to each individual Applicant based on an annual energy load ratio share.

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[3] This was a potential error in the preliminary analysis numbers that were provided to Staff in Docket No. 15-05017 and that was discussed with NV Energy at the July 8, 2015, preliminary analysis meeting.

[4] This was a potential error in the preliminary analysis numbers that were provided to Staff in Docket No. 15-05017 and that was discussed with NV Energy at the July 8, 2015, preliminary analysis meeting.

[5] Since the Applicants are going to be paying, in any exit fee calculation, the cost of complying with the Nevada renewable portfolio standard ("RPS") for the exit fee period, it may be appropriate to credit to the Applicants with some of the future portfolio credits as part of their departure. However, since each Applicant is responsible for repaying its load ratio share of the portfolio credits NPC has borrowed from SPPC on behalf of customers, it may be appropriate to retain some or all of these same portfolio credits as repayment of the portfolio credits the Applicants are responsible for repaying to SPPC.

BTGR RATE ANALYSIS

- As stated above, use LVSC's, Wynn's, and MGM's actual billing determinates during the 12-month period April 2014 through March 2015 for each of the service locations identified in Exhibit 1 of LVSC's Exit Application, Exhibit 1 of Wynn's Exit Application, and Revised Exhibit B of MGM's Exit Application as LVSC's, Wynn's, and MGM's ten-year load forecast, respectively, with the following adjustments:
  - MGM Properties 1 and 12 are served from the same substation but are separate premises. [6]
  - Shape the output of the MGM owned 6.4 MW solar photovoltaic ("PV") system located at the Mandalay Bay for all 8760 hours in the year and include the shaped output as an offset to the Mandalay Bay's billing determinates, but do not include any other solar PV systems planned or under construction nor any planned demand additions.[7]
  - Offset the output of the MGM's owned CHP generating facility, located at the Aria, from the Aria's billing determinates.[8]
- Assume all of the accounts or service identified in Exhibit 1 of LVSC's Exit Application, Exhibit 1 of Wynn's Exit Application, and Revised Exhibit B of MGM's Exit Application and modified above will remain a distribution and transmission customer after their departure on February 1, 2016.
- Use NPC's currently approved FERC transmission rates, as well as the BTGR rates approved by the Commission in Docket No. 14-05004.
  - BTGR and FERC rates should be held constant for the length of the analysis period.
  - Exclude the energy efficiency rates in this analysis.[9]
- Perform a ten-year rate analysis (February 1, 2016, to January 31, 2026), with takeoff points at years three, six and ten.[10]

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[6] This was a potential error in the preliminary analysis numbers that were provided to Staff in Docket No. 15-05017 and that was discussed with NV Energy at the July 8, 2015, preliminary analysis meeting.

[7] This was a potential error in the preliminary analysis numbers that were provided to Staff in Docket No. 15-05017 and that was discussed with NV Energy at the July 8, 2015, preliminary analysis meeting.

[8] This was a potential error in the preliminary analysis numbers that were provided to Staff in Docket No. 15-05017 and that was discussed with NV Energy at the July 8, 2015, preliminary analysis meeting.

[9] Staff's current position is that upon departure some repayment amount of historic energy efficiency rebates provided to the customer is appropriate and with this repayment future energy efficiency rate charges should not be applied since the departed customer is no longer being serviced by NV Energy and cannot participate in energy efficiency programs.

[10] At this time, Staff has not decided which timeframe it will use for the exit fee calculation.

- Include the revenue associated with those generation projects/facilities that have been given resource planning approval but are not yet in rates. For example, include the facilities, such as LV Cogen, SunPeak, and the 15 MW Nellis Solar PV facilities, that were approved by the Commission in the ERCR filing, Docket No. 14-05003.
- At the end of the three, six and ten year analysis period, use the load ratio share (the Applicant's forecasted yearly energy use vs. NPC's total forecasted energy sales, which should include Switch's and the Applicant's yearly energy usage contained in Docket Nos. 14-11007, 15-05002, and 15-05006, and 15-05017) to determine the Applicant's cost responsibility for all regulatory assets that have been explicitly approved through a Commission decision in an IRP or GRC filing. For example, the retirement costs of Reid Gardner units 1-3 and the decommissioning and site remediation are costs that should be included in the analysis. Also, the Navajo remaining net book value costs.
- Include LVSC's, Wynn's and MGM's energy load ratio share of the revenue requirements associated with the generation facility additions contained in the preferred plan, Case B, from NPC's IRP filing, Docket No. 15-07004, for NPC's acquisition of the 25% share of the Silverhawk Generating Station on May 1, 2017, for $77 million

ANALYSES #2 – IMPACT METHODOLOGY WITH NON-BYPASSABLE RATES

NON-BYPASSABLE RATE

- After the BTER impact is calculated (as outlined above), calculate the portion of the BTER associated with the out-of-the-money costs of the long-term renewable energy contracts ("R-BTER") that NPC has entered into and subtract those costs from the BTER impact fee to determine the "net BTER".
    - R-BTER Calculation:
        - Calculate and capture the hourly marginal energy cost from the Change Case (no sales) PROMOD analysis and convert it into an average monthly marginal energy cost.
        - Calculate the hourly marginal energy cost from the Change Case (with sales) PROMOD analysis and convert into an average monthly marginal energy cost
        - Average of the calculated average monthly marginal costs for the sales and no sales cases to determine a combined average monthly marginal cost (similar to the off-system sales calculation).
        - Multiply the combined average monthly marginal cost by the monthly output for each renewable energy resources under contract that are identified in Table REN-1 of the Supply Side Plan, Volume 12 in Docket No. 15-07004 for the 10 year period to determine the monthly energy cost of these contracts.
        - For the months of July, August, and September, multiply the capacity amount for each renewable energy resource that is identified in Figure

EA-30 of the Supply Side Plan, Volume 12 in Docket No. 15-07004 by the summer monthly capacity price contained in the fuel and purchase power forecast to obtain the capacity cost associated with the renewable energy resource. Add the capacity cost to the monthly energy value/cost.

        - Sum all of the individual resource monthly costs to determine the monthly R-BTER cost

    - Subtract the monthly RBTER cost from the monthly BTER cost to determine the monthly "net BTER" cost.

EXIT FEE CALCULATION FORMAT

- For Analyses 1 outlined above "Traditional Impact Methodology", on the "Impact Summary (A-1)" schedule list the impact fee for each of the following rate components:
    - BTGR
    - BTER
    - Merrill Lynch
    - Renewable Energy Program Rate
    - Energy Efficiency Program Rate
    - Temporary Renewable Energy Development Rate
    - Regulatory Assets
    - 15 MW Nellis Solar PV
    - 274 MW Las Vegas Cogen Facility
    - 222 MW SunPeak Facility
    - Acquisition of the 25 percent share of the Silverhawk Generating Statoin
    - The Required 5 percent Franchise Fee

- For Analyses 2 outlined above, "Non-bypassable rates", on the "Impact Summary (A-1)" schedule, individually list the impact fee for each of the following rate components
    - BTGR
    - Net BTER[11]
    - 15 MW Nellis Solar PV
    - 274 MW Las Vegas Cogen Facility
    - 222 MW SunPeak Facility
    - Acquisition of the 25 percent share of the Silverhawk Generating Station
    - The Required 5 percent Franchise Fee

[11] Individual workpapers should be provided that show how the BTER impact was extracted into an R-BTER and Net BTER component.

- Since "non-bypassable rates" will be assumed to be implemented for Merrill Lynch, REPR, TRED, and the Regulatory Assets/SB123 related charges, exclude all other individual line items from this second analysis.

ATTACHMENT 2

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS
(IN THOUSANDS)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
No No		Reference	Feb - Dec 2016	Jan - Dec 2017	Jan - Dec 2018	Jan - Dec 2019	Jan - Dec 2020	Jan - Dec 2021	Jan 2022	2023	2024	2025	2026	Total	Present Value Value 8 09%	Levelized Payment Payment	No No
1	Estimated Charge Necessary to Maintain BTGR Neutrality	Schedule A-2, Line 31	$ 14,591	$ 14,548	$ 14,548	$ 14,548	$ 14,548	$ 14,548	$ (43)	$ -	$ -	$ -	$ -	$ 87,288	$ 67,520	$ 14,645	1
2																	2
3	Estimated Charge Necessary to Maintain BTER Neutrality	Schedule A-2, Line 54	8,194	9,470	1,693	2,486	(1,060)	(3,075)	167	-	-	-	-	17,875	16,411	3,560	3
4																	4
5	*ERCR New Generation Annual Revenue Requirements*																5
6	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW	Schedule A-2, Line 59	348	313	288	270	252	239	19	-	-	-	-	1,729	1,357	294	6
7	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015	Schedule A-2, Line 60	949	912	875	840	806	772	62	-	-	-	-	5,216	4,063	881	7
8	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015	Schedule A-2, Line 61	128	118	110	102	95	90	7	-	-	-	-	650	510	111	8
9	Obligation for acquisition of 25% share of Silverhawk	Schedule A-2, Line 62	-	383	568	546	524	503	40	-	-	-	-	2,564	1,886	409	9
10			-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
11			-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
12			-	-	-	-	-	-	-	-	-	-	-	-	-	-	12
13			-	-	-	-	-	-	-	-	-	-	-	-	-	-	13
14																	14
15			$ 24,210	$ 25,744	$ 18,082	$ 18,792	$ 15,165	$ 13,077	$ 252	$ -	$ -	$ -	$ -	$ 115,322	$ 91,747	$ 19,900	15
16																	16
17	Local Government Fee														4,587		17
18																	18
19															$ 96,334		19
20																	20
21																	21
22		The 6-year impact is detrimental to the Company's system, therefore, the impact fee is.														$\boxed{\$ \ 96,334}$	22
23																	23
24																	24
25		Amounts in parentheses indicate that the change in costs or revenues are negative If the Total Impact is a negative amount, there is a benefit for the customer to depart, if the Total Impact is a positive amount , there is a cost for the customer															25
26		to depart															26

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS

Line No	(a) BTGR Impact	(b) Schedule Reference	(c) Feb - Dec 2016	(d) Jan - Dec 2017	(e) Jan - Dec 2018	(f) Jan - Dec 2019	(g) Jan - Dec 2020	(h) Jan - Dec 2021	(i) Jan 2022	(j) 2023	(k) 2024	(l) 2025	(m) 2026	(n) Total	Line No
1	Bundled Revenues-BTGR														1
2															2
3	GS	Schedule A-3a, Page 4, Lines 26 thru 36	1,246	1,381	1,381	1,381	1,381	1,381	135	-	-	-	-	$ 8,286	3
4	LGS-1	Schedule A-3b, Page 4, Lines 26 thru 36	156,379	174,279	174,279	174,279	174,279	174,279	17,900	-	-	-	-	1,045,674	4
5	LGS-2S	Schedule A-3c, Page 4, Lines 26 thru 36	641,205	671,962	671,962	671,962	671,962	671,962	30,757	-	-	-	-	4,031,772	5
6	LGS-3S	Schedule A-3d, Page 4, Lines 26 thru 36	719,390	745,821	745,821	745,821	745,821	745,821	26,431	-	-	-	-	4,474,926	6
7	LGS-3P	Schedule A-3e, Page 4, Lines 26 thru 36	7,724,189	8,029,251	8,029,251	8,029,251	8,029,251	8,029,251	305,062	-	-	-	-	48,175,506	7
8	LGS-3T	Schedule A-3f, Page 4, Lines 26 thru 36	3,233,768	3,309,289	3,309,289	3,309,289	3,309,289	3,309,289	75,521	-	-	-	-	19,855,734	8
9	LGS-XS	Schedule A-3g, Page 4, Lines 26 thru 36	15,499	16,497	16,497	16,497	16,497	16,497	998	-	-	-	-	98,982	9
10	LGS-XP	Schedule A-3h, Page 4, Lines 26 thru 36	5,617,996	5,835,518	5,835,518	5,835,518	5,835,518	5,835,518	217,522	-	-	-	-	35,013,108	10
11	LGS-XT	Schedule A-3i, Page 4, Lines 26 thru 36	4,741,605	4,902,473	4,902,473	4,902,473	4,902,473	4,902,473	160,868	-	-	-	-	29,414,838	11
12	LSR2-3T	Schedule A-3j, Page 4, Lines 26 thru 36	3,333,340	3,471,127	3,471,127	3,471,127	3,471,127	3,471,127	137,787	-	-	-	-	20,826,762	12
13	LSR3-XP	Schedule A-3k, Page 4, Lines 26 thru 36	1,361,835	1,411,834	1,411,834	1,411,834	1,411,834	1,411,834	49,999	-	-	-	-	8,471,004	13
14			27,546,452	28,569,432	28,569,432	28,569,432	28,569,432	28,569,432	1,022,980	-	-	-	-	171,416,592	14
15															15
16	Less Unbundled Revenues Transmission & Distribution Only Service Revenue														16
17															17
18	GS	Schedule A-3a, Page 7, Lines 1 thru 11	1,215	1,326	1,326	1,326	1,326	1,326	111	-	-	-	-	7,956	18
19	LGS-1	Schedule A-3b, Page 7, Lines 1 thru 11	136,054	147,327	147,327	147,327	147,327	147,327	11,273	-	-	-	-	883,962	19
20	LGS-2S	Schedule A-3c, Page 7, Lines 1 thru 11	336,412	364,522	364,522	364,522	364,522	364,522	28,110	-	-	-	-	2,187,132	20
21	LGS-3S	Schedule A-3d, Page 7, Lines 1 thru 11	395,532	427,696	427,696	427,696	427,696	427,696	32,164	-	-	-	-	2,566,176	21
22	LGS-3P	Schedule A-3e, Page 7, Lines 1 thru 11	4,209,554	4,574,212	4,574,212	4,574,212	4,574,212	4,574,212	364,658	-	-	-	-	27,445,272	22
23	LGS-3T	Schedule A-3f, Page 7, Lines 1 thru 11	1,263,760	1,364,126	1,364,126	1,364,126	1,364,126	1,364,126	100,366	-	-	-	-	8,184,756	23
24	LGS-XS	Schedule A-3g, Page 7, Lines 1 thru 11	8,574	9,431	9,431	9,431	9,431	9,431	857	-	-	-	-	56,586	24
25	LGS-XP	Schedule A-3h, Page 7, Lines 1 thru 11	2,580,990	2,791,903	2,791,903	2,791,903	2,791,903	2,791,903	210,913	-	-	-	-	16,751,418	25
26	LGS-XT	Schedule A-3i, Page 7, Lines 1 thru 11	2,044,524	2,215,179	2,215,179	2,215,179	2,215,179	2,215,179	170,655	-	-	-	-	13,291,074	26
27	LSR2-3T	Schedule A-3j, Page 7, Lines 1 thru 11	919,321	972,977	972,977	972,977	972,977	972,977	53,656	-	-	-	-	5,837,862	27
28	LSR3-XP	Schedule A-3k, Page 7, Lines 1 thru 11	1,059,476	1,152,703	1,152,703	1,152,703	1,152,703	1,152,703	93,227	-	-	-	-	6,916,218	28
29			12,955,412	14,021,402	14,021,402	14,021,402	14,021,402	14,021,402	1,065,990	-	-	-	-	84,128,412	29
30															30
31	BTGR Impact - Cost / (Benefit) from the Departure		14,591,040	14,548,030	14,548,030	14,548,030	14,548,030	14,548,030	(43,010)	-	-	-	-	87,288,180	31
32															32
33	BTER Impact														33
34															34
35	Change in Net Fuel and Purchased Power Co:	Schedule A-4a, Page 1, Line 12 X 1000	(24,789,874)	(28,554,552)	(34,004,729)	(39,083,369)	(46,586,800)	(52,609,512)	(2,749,346)	-	-	-	-	(228,378,182)	35
36															36
37	Bundled Revenues-BTER														37
38															38
39	GS	Schedule A-3a, Page 4, Lines 14 thru 24	644	763	717	833	913	993	77	-	-	-	-	4,940	39
40	LGS-1	Schedule A-3b, Page 4, Lines 14 thru 24	182,394	209,119	196,325	228,612	250,378	272,421	14,933	-	-	-	-	1,354,182	40
41	LGS-2S	Schedule A-3c, Page 4, Lines 14 thru 24	697,632	805,032	755,785	880,080	963,865	1,048,718	62,514	-	-	-	-	5,213,626	41
42	LGS-3S	Schedule A-3d, Page 4, Lines 14 thru 24	581,581	654,680	614,626	715,708	783,848	852,852	35,004	-	-	-	-	4,238,299	42
43	LGS-3P	Schedule A-3e, Page 4, Lines 14 thru 24	8,796,220	10,188,304	9,565,027	11,138,061	12,198,444	13,272,316	827,690	-	-	-	-	65,986,062	43
44	LGS-3T	Schedule A-3f, Page 4, Lines 14 thru 24	5,831,211	6,746,374	6,333,660	7,375,274	8,077,427	8,788,512	540,701	-	-	-	-	43,693,159	44
45	LGS-XS	Schedule A-3g, Page 4, Lines 14 thru 24	25,007	29,472	27,667	32,219	35,288	38,391	2,881	-	-	-	-	190,925	45
46	LGS-XP	Schedule A-3h, Page 4, Lines 14 thru 24	5,585,227	6,414,838	6,022,406	7,012,832	7,680,478	8,356,618	469,017	-	-	-	-	41,541,416	46
47	LGS-XT	Schedule A-3i, Page 4, Lines 14 thru 24	6,455,063	7,471,211	7,014,152	8,167,679	8,945,271	9,732,755	601,748	-	-	-	-	48,387,879	47
48	LSR2-3T	Schedule A-3j, Page 4, Lines 14 thru 24	3,369,729	3,819,813	3,586,132	4,175,896	4,573,458	4,976,075	230,457	-	-	-	-	24,731,560	48
49	LSR3-XP	Schedule A-3k, Page 4, Lines 14 thru 24	1,560,373	1,801,409	1,691,207	1,969,339	2,156,826	2,346,698	140,674	-	-	-	-	11,666,526	49
50			33,085,081	38,141,015	35,807,704	41,696,533	45,666,196	49,686,349	2,925,696	-	-	-	-	247,008,574	50
51	Mill Tax Impact (Mill Tax Rate 0 306%)		0 99694	0 99694	0.99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	51
52			32,983,841	38,024,303	35,698,132	41,568,942	45,526,457	49,534,309	2,916,743	-	-	-	-	246,252,728	52
53															53
54	BTER Impact - Cost / (Benefit) of the Departure		8,193,967	9,469,751	1,693,403	2,485,573	(1,060,343)	(3,075,203)	167,397	-	-	-	-	17,874,546	54
55															55
56															56
57	Other Obligations														57
58															58
59	ERCR Nellis PV Self Build 2016 15 MW	Schedule A-5f, Column (b), Lines 25-34	347,797	312,758	288,301	270,194	252,088	238,744	19,180	-	-	-	-	1,729,062	59
60	ERCR LVC Bundled 274 MW 2015	Schedule A-5f, Column (c), Lines 25-34	949,470	911,866	875,434	840,079	805,731	772,314	61,646	-	-	-	-	5,216,539	60
61	ERCR SunPeak 222 MW 2015	Schedule A-5f, Column (d), Lines 25-34	128,234	117,916	109,766	101,615	95,091	90,193	7,108	-	-	-	-	649,922	61
62	IRP Acq of the 25% Share of Silverhawk	Schedule A-5f, Column (e), Lines 25-34	-	382,784	568,358	545,940	524,220	503,147	40,223	-	-	-	-	2,564,671	62
63			-	-	-	-	-	-	-	-	-	-	-	-	63
64			-	-	-	-	-	-	-	-	-	-	-	-	64
65			-	-	-	-	-	-	-	-	-	-	-	-	65
66			-	-	-	-	-	-	-	-	-	-	-	-	66
67															67
68			1,425,502	1,725,324	1,841,858	1,757,827	1,677,129	1,604,397	128,157	-	-	-	-	10,160,195	68
69															69
70	Cost / (Benefit) of the Departure		$ 24,210,509	$ 25,743,106	$ 18,083,292	$ 18,791,430	$ 15,164,816	$ 13,077,224	$ 252,544	$ -	$ -	$ -	$ -	$ 115,322,921	70
71															71
72															72

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS

Line No	(a)		(b)	(c)	Line No
1					1
2					2
3					3
4					4
5	Net Present Value of One Time Payment (Rate of Return 8 09% per Docket No 14-05004)				5
6	Estimated Departure Date of February 01, 2016				6
7	BTGR Impact	8 09%	$ 67,519,865		7
8	BTER Impact		$ 16,411,217		8
9	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW		$ 1,356,961		9
10	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015		$ 4,062,532		10
11	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015		$ 509,645		11
12	Obligation for ERCR Approved Gen IRP Acq of the 25% Share of Silverhawk		$ 1,885,653		12
13			$ 91,745,873		13
14	Local Government Fee	5%	4,587,294		14
15					15
16	Total Impact Fee		$ 96,333,167		16
17					17
18			Annual Payment		18
19	Annual Payments (Rate of Return 8 09%, per Docket No 14-05004)		For 6 Years	Total	19
20					20
21	BTGR Impact		$ 14,645,486	$ 87,872,916	21
22	BTER Impact		$ 3,559,697	$ 21,358,182	22
23	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW		$ 294,333	$ 1,765,998	23
24	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015		$ 881,189	$ 5,287,134	24
25	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015		$ 110,545	$ 663,270	25
26	Obligation for ERCR Approved Gen IRP Acq of the 25% Share of Silverhawk		$ 409,010	$ 2,454,060	26
27					27
28			$ 19,900,260	$ 119,401,560	28

ATTACHMENT 3

Nevada Power Company
d/b/a NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO.:	15-07004	**REQUEST DATE:**	7/14/2015
REQUEST NO.:	Staff 031	**NVE KEYWORD:**	Silverhawk Historical Capital Expenditures
REQUESTER:	Cameron	**RESPONDER:**	Smith, Robin

REQUEST:

Reference: Silverhawk Future Capital Expenditures

Question: Please provide Staff with the most recent 10 year business plan for the Silverhawk generating unit including a projection of capital spending.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENTS CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One

RESPONSE:

The Arrow Canyon Complex is comprised of the Lenzie, Harry Allen and Silverhawk generating stations. Attached is Arrow Canyon's Fall 2014 10-Year Business Plan with information specific to Silverhawk.

Projected capital expenditures for Silverhawk are as follows:

2015	$	9,634,590
2016	$	2,545,000
2017	$	11,027,668
2018	$	12,081,636
2019	$	1,119,029
2020	$	730,000
2021	$	285,639
2022	$	16,844,393
2023	$	75,000
2024	$	2,741,667
2025	$	4,075,000

ATTACHMENT 4

MGM's Energy Load Ratio Share of the Variable Operations and Maintence Credit (in thousands)

DIFFERENCE: BASE CASE - CHANGE CASE (SALES)

	1	2	3	4	5	6	7	8	9	10	11	12	Total
2016	$ -	$ 80	$ 73	$ 135	$ 168	$ 198	$ 346	$ 276	$ 170	$ 139	$ 87	$ 113	$ 1,785
2017	$ 78	$ 145	$ 59	$ 99	$ 123	$ 173	$ 287	$ 170	$ 131	$ 183	$ 102	$ 79	$ 1,628
2018	$ 78	$ 112	$ 101	$ 90	$ 118	$ 194	$ 258	$ 260	$ 188	$ 194	$ 128	$ 96	$ 1,817
2019	$ 154	$ 122	$ 144	$ 127	$ 166	$ 223	$ 281	$ 307	$ 223	$ 152	$ 130	$ 150	$ 2,180
2020	$ 131	$ 161	$ 116	$ 127	$ 155	$ 218	$ 279	$ 290	$ 267	$ 169	$ 140	$ 124	$ 2,176
2021	$ 131	$ 163	$ 125	$ 90	$ 146	$ 271	$ 308	$ 313	$ 243	$ 204	$ 193	$ 144	$ 2,330
2022	$ 133												$ 133
Total													$ 12,049

DIFFERENCE: BASE CASE - CHANGE CASE (NO SALES)

	1	2	3	4	5	6	7	8	9	10	11	12	Total
2016	$ -	$ 141	$ 129	$ 126	$ 181	$ 213	$ 344	$ 323	$ 193	$ 210	$ 133	$ 136	$ 2,130
2017	$ 133	$ 134	$ 145	$ 110	$ 153	$ 171	$ 306	$ 360	$ 163	$ 179	$ 104	$ 122	$ 2,080
2018	$ 130	$ 118	$ 134	$ 104	$ 111	$ 238	$ 304	$ 293	$ 289	$ 234	$ 101	$ 141	$ 2,197
2019	$ 149	$ 109	$ 149	$ 137	$ 164	$ 226	$ 291	$ 317	$ 259	$ 147	$ 129	$ 136	$ 2,214
2020	$ 144	$ 151	$ 121	$ 130	$ 166	$ 220	$ 282	$ 296	$ 283	$ 171	$ 132	$ 146	$ 2,243
2021	$ 125	$ 170	$ 141	$ 98	$ 149	$ 272	$ 307	$ 317	$ 263	$ 209	$ 134	$ 175	$ 2,360
2022	$ 140												$ 140
Total													$ 13,364

AVERAGE OF SALES AND NO SALES CASES

	1	2	3	4	5	6	7	8	9	10	11	12	Total
2016	$ -	$ 111	$ 101	$ 130	$ 175	$ 205	$ 345	$ 299	$ 181	$ 175	$ 110	$ 125	$ 1,958
2017	$ 105	$ 139	$ 102	$ 105	$ 138	$ 172	$ 296	$ 265	$ 147	$ 181	$ 103	$ 100	$ 1,854
2018	$ 104	$ 115	$ 118	$ 97	$ 115	$ 216	$ 281	$ 277	$ 238	$ 214	$ 115	$ 118	$ 2,007
2019	$ 152	$ 115	$ 146	$ 132	$ 165	$ 224	$ 286	$ 312	$ 241	$ 150	$ 129	$ 143	$ 2,197
2020	$ 137	$ 156	$ 118	$ 128	$ 161	$ 219	$ 281	$ 293	$ 275	$ 170	$ 136	$ 135	$ 2,209
2021	$ 128	$ 167	$ 133	$ 94	$ 147	$ 271	$ 307	$ 315	$ 253	$ 206	$ 163	$ 160	$ 2,345
2022	$ 137												$ 137
Total													$ 12,706

	2016	2017	2018	2019	2020	2021	2022	TOTAL
Total O&M Credit	**$ 1,958**	**$ 1,854**	**$ 2,007**	**$ 2,197**	**$ 2,209**	**$ 2,345**	**$ 137**	**$ 12,706**
MGM Load Ratio	**69.20%**	**69.20%**	**69.20%**	**69.20%**	**69.20%**	**69.20%**	**68.50%**	
MGM O&M Credit	**$ 1,355**	**$ 1,283**	**$ 1,389**	**$ 1,520**	**$ 1,529**	**$ 1,623**	**$ 94**	**$ 8,792**

ATTACHMENT 5

704B Demand Side Management Recapture Payment Methodology

Nevada Power Company ("NPC") incurs costs in providing the Commercial Incentives Program as part of its Demand Side Management ("DSM") portfolio. The costs include, for example, rebates, implementation contractor costs, third party measurement and verification costs, and NPC employee salaries and resources devoted to designing and implementing the program. These costs are recovered from all NPC rate payers through an Energy Efficiency Program Rate ("EEPR") with the premise that all rate payers, not just participants, receive benefits from the program over the program's effective useful life ("EUL"). Thus, if a 704B applicant exits from NPC's bundled service before the end of a project's EUL, the applicant would take the remaining benefits all for itself - without sharing the benefits with remaining customers who funded the program. Accordingly, to the extent the applicant keeps benefits to itself by leaving NPC's grid, a portion of the financial support the applicant received as a bundled customer must be returned to remaining customers.

The DSM payback amount is based upon a remaining EUL of the total rebates received by the applicant and an implementation amount that is a portion of all implementation costs for the Commercial Retrofit DSM Program. The rebate portion of the payback amount is taken directly from the annual amounts received by the applicant as documented by NPC. The implementation amount allocated to the applicant is calculated as the ratio (in percentage) of total rebates the applicant received to the total rebate amount given to all program participants for each year. For example, if the applicant received 10% of the rebates in 2014 the customer would also be allocated 10% of the implementation costs associated with the Program. The annual rebate amounts utilized in the calculation were obtained from NPC in Staff Data Request No. 1. The Program total rebates and implementation costs are the inputs used by NPC in the PortfolioPro analysis in Docket Nos. 12-06053, 13-07002, 14-07007, 15-07004, and Staff Data Request Nos. 3 and 4 in Docket 15-05002.

The sum of the rebate amount and the administrative amount is then divided by the program's EUL in months, which yields the cost per month of the program. The payback amount is calculated as the cost per month of the program multiplied by the remaining EUL in months, corresponding to the period that the applicant keeps the benefits to itself.

The costs associated with the Commercial Incentives Program have already been collected through the EEPR. The DSM Payback amount calculated above and paid by the applicant will become a rebate to remaining rate payers who had partially paid for the full Commercial Incentive Program in the past. However, the applicant also paid EEPRs based upon the full Program cost and should be given an EEPR credit to offset the DSM Payback amount being calculated. The EEPR credit is calculated using a percentage change in EEPR revenue requirement and applying that percentage decrease to the amount of EEPR paid by the applicant.[1] At the time of the analysis, only 2014 annual billing determinants were available therefore Staff utilized said 2014 billing determinants for all Program years to estimate the EEPR amount paid by the applicant for each year. Specific billing determents will be updated in Staff Testimony.

The payback amount for years 2011, 2012, 2013, 2014, and 2015 are added together to come up with a total customer specific DSM payback amount.

[1] The percentage change in revenue requirement includes the DSM Payback costs calculated in Docket Nos. 15-05002, 15-05006, and 15-05017.

MGM DSM Recapture Payment		
Total Rebates	$	2,726,278.07
Total Implementation Costs	$	2,187,354.97
Total MGM Costs	$	4,913,633.04
Remaing UsefulLife Cost	$	3,527,001.78
EEPR Credit	$	300,632.54
MGM DSM Recapture Payment	**$**	**3,226,369.24**

2011

12-06053

Total MGM Rebates	$ 635,242.32
MGM Rebate %	15%
Total Implementation Costs	$ 3,401,107
Total MGM Implementation Costs	$ 496,976.57
Total 2011 MGM Costs	$1,132,218.89
Useful Life Months	126
Cost per month	$8,985 86
months past	55
Remaining cost	$637,996.36
EEPR Credit	$ 33,383 00
Final Remaining Cost	$604,613 36

2012

13-07002

Total MGM Rebates	$ 720,662.88
MGM Rebate %	17 49%
Total Implementation Costs	$ 3,287,608 00
Total MGM Implementation Costs	$ 574,839.15
Total 2012 MGM Costs	$1,295,502.03
Useful Life Months	126
Cost per month	$10,281 76
months past	43
Remaining cost	$853,386.26
EEPR Credit	$ 49,943.64
Final Remaining Cost	$803,442.62

2013

14-07007

Total MGM Rebates	$ 648,264.82
MGM Rebate %	17%
Total Implementation Costs	$ 3,242,842 00
Total MGM Implementation Costs	$ 556,573.94
Total 2013 MGM Costs	$1,204,838.76
Useful Life Months	126
Cost per month	$9,562 21
months past	31
Remaining cost	$908,410 17
EEPR Credit	$ 64,772 29
Final Remaining Cost	$843,637.88

2014

13-07002/DR #4

Total MGM Rebates	$ 569,455.18
MGM Rebate %	13%
Total Implementation Costs	$ 3,425,740 00
Total MGM Implementation Costs	$ 436,424.72
Total 2014 MGM Costs	$1,005,879.90
Useful Life Months	126
Cost per month	$7,983.17
months past	19
Remaining cost	$854,199.59
EEPR Credit	$ 85,391 56
Final Remaining Cost	$768,808.03

2015

13-07002/DR #4

Total MGM Rebates	$ 152,652.87
MGM Rebate %	3%
Total Implementation Costs	$ 4,511,400 00
Total MGM Implementation Costs	$ 122,540 60
Total 2015 MGM Costs	$275,193 47
Useful Life Months	126
Cost per month	$2,184 08
months past	1
Remaining cost	$273,009.39
EEPR Credit	$ 67,142 04
Final Remaining Cost	$205,867.35

ATTACHMENT 6

MGM's Energy Efficiency Lump Sum Payment			
Class	EE Rate	2016 Energy Usage (kWh)	EE Payment
Total			$1,301,702.36

ATTACHMENT 7

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS
(IN THOUSANDS)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
No No		Reference	Feb - Dec 2016	Jan - Dec 2017	Jan - Dec 2018	Jan - Dec 2019	Jan - Dec 2020	Jan - Dec 2021	Jan 2022	2023	2024	2025	2026	Total	Present Value Value 8 09%	Levelized Payment Payment	No No
1	Estimated Charge Necessary to Maintain BTGR Neutrality	Schedule A-2, Line 31	$ 14,655	$ 14,612	$ 14,612	$ 14,612	$ 14,612	$ 14,612	$ (43)	$ -	$ -	$ -	$ -	$ 87,672	$ 67,816	$ 14,710	1
2																	2
3	Estimated Charge Necessary to Maintain BTER Neutrality	Schedule A-2, Line 54	8,279	9,561	1,779	2,585	(951)	(2,956)	167	-	-	-	-	18,464	16,861	3,657	3
4																	4
5	*ERCR New Generation Annual Revenue Requirements*																5
6	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW	Schedule A-2, Line 59	348	313	288	270	252	239	19	-	-	-	-	1,729	1,357	294	6
7	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015	Schedule A-2, Line 60	949	912	875	840	806	772	62	-	-	-	-	5,216	4,063	881	7
8	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015	Schedule A-2, Line 61	128	118	110	102	95	90	7	-	-	-	-	650	510	111	8
9	Obligation for acquisition of 25% share of Silverhawk	Schedule A-2, Line 62	-	383	568	546	524	503	40	-	-	-	-	2,564	1,886	409	9
10			-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
11			-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
12			-	-	-	-	-	-	-	-	-	-	-	-	-	-	12
13			-	-	-	-	-	-	-	-	-	-	-	-	-	-	13
14																	14
15			$ 24,359	$ 25,899	$ 18,232	$ 18,955	$ 15,338	$ 13,260	$ 252	$ -	$ -	$ -	$ -	$ 116,295	$ 92,493	$ 20,062	15
16																	16
17	Local Government Fee														4,625		17
18																	18
19															$ 97,118		19
20																	20
21																	21
22		The 6-year impact is detrimental to the Company's system, therefore, the impact fee is														$ 97,118	22
23																	23
24																	24
25		Amounts in parentheses indicate that the change in costs or revenues are negative. If the Total Impact is a negative amount, there is a benefit for the customer to depart, if the Total Impact is a positive amount , there is a cost for the customer															25
26		to depart															26

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS

Line No	(a) BTGR Impact	(b) Schedule Reference	(c) Feb - Dec 2016	(d) Jan - Dec 2017	(e) Jan - Dec 2018	(f) Jan - Dec 2019	(g) Jan - Dec 2020	(h) Jan - Dec 2021	(i) Jan 2022	(j) 2023	(k) 2024	(l) 2025	(m) 2026	(n) Total	Line No
1	Bundled Revenues-BTGR														1
2															2
3	GS	Schedule A-3a, Page 4, Lines 26 thru 36	1,406	1,541	1,541	1,541	1,541	1,541	135	-	-	-	-	$ 9,246	3
4	LGS-1	Schedule A-3b, Page 4, Lines 26 thru 36	228,587	246,487	246,487	246,487	246,487	246,487	17,900	-	-	-	-	1,478,922	4
5	LGS-2S	Schedule A-3c, Page 4, Lines 26 thru 36	641,205	671,962	671,962	671,962	671,962	671,962	30,757	-	-	-	-	4,031,772	5
6	LGS-3S	Schedule A-3d, Page 4, Lines 26 thru 36	719,390	745,821	745,821	745,821	745,821	745,821	26,431	-	-	-	-	4,474,926	6
7	LGS-3P	Schedule A-3e, Page 4, Lines 26 thru 36	7,724,189	8,029,251	8,029,251	8,029,251	8,029,251	8,029,251	305,062	-	-	-	-	48,175,506	7
8	LGS-3T	Schedule A-3f, Page 4, Lines 26 thru 36	3,233,768	3,309,289	3,309,289	3,309,289	3,309,289	3,309,289	75,521	-	-	-	-	19,855,734	8
9	LGS-XS	Schedule A-3g, Page 4, Lines 26 thru 36	15,499	16,497	16,497	16,497	16,497	16,497	998	-	-	-	-	98,982	9
10	LGS-XP	Schedule A-3h, Page 4, Lines 26 thru 36	5,617,996	5,835,518	5,835,518	5,835,518	5,835,518	5,835,518	217,522	-	-	-	-	35,013,108	10
11	LGS-XT	Schedule A-3i, Page 4, Lines 26 thru 36	4,741,605	4,902,473	4,902,473	4,902,473	4,902,473	4,902,473	160,868	-	-	-	-	29,414,838	11
12	LSR2-3T	Schedule A-3j, Page 4, Lines 26 thru 36	3,333,340	3,471,127	3,471,127	3,471,127	3,471,127	3,471,127	137,787	-	-	-	-	20,826,762	12
13	LSR3-XP	Schedule A-3k, Page 4, Lines 26 thru 36	1,361,835	1,411,834	1,411,834	1,411,834	1,411,834	1,411,834	49,999	-	-	-	-	8,471,004	13
14			27,618,820	28,641,800	28,641,800	28,641,800	28,641,800	28,641,800	1,022,980	-	-	-	-	171,850,800	14
15															15
16	Less Unbundled Revenues Transmission & Distribution Only Service Revenue														16
17															17
18	GS	Schedule A-3a, Page 7, Lines 1 thru 11	1,223	1,334	1,334	1,334	1,334	1,334	111	-	-	-	-	8,004	18
19	LGS-1	Schedule A-3b, Page 7, Lines 1 thru 11	144,646	155,919	155,919	155,919	155,919	155,919	11,273	-	-	-	-	935,514	19
20	LGS-2S	Schedule A-3c, Page 7, Lines 1 thru 11	336,412	364,522	364,522	364,522	364,522	364,522	28,110	-	-	-	-	2,187,132	20
21	LGS-3S	Schedule A-3d, Page 7, Lines 1 thru 11	395,532	427,696	427,696	427,696	427,696	427,696	32,164	-	-	-	-	2,566,176	21
22	LGS-3P	Schedule A-3e, Page 7, Lines 1 thru 11	4,209,554	4,574,212	4,574,212	4,574,212	4,574,212	4,574,212	364,658	-	-	-	-	27,445,272	22
23	LGS-3T	Schedule A-3f, Page 7, Lines 1 thru 11	1,263,760	1,364,126	1,364,126	1,364,126	1,364,126	1,364,126	100,366	-	-	-	-	8,184,756	23
24	LGS-XS	Schedule A-3g, Page 7, Lines 1 thru 11	8,574	9,431	9,431	9,431	9,431	9,431	857	-	-	-	-	56,586	24
25	LGS-XP	Schedule A-3h, Page 7, Lines 1 thru 11	2,580,990	2,791,903	2,791,903	2,791,903	2,791,903	2,791,903	210,913	-	-	-	-	16,751,418	25
26	LGS-XT	Schedule A-3i, Page 7, Lines 1 thru 11	2,044,524	2,215,179	2,215,179	2,215,179	2,215,179	2,215,179	170,655	-	-	-	-	13,291,074	26
27	LSR2-3T	Schedule A-3j, Page 7, Lines 1 thru 11	919,321	972,977	972,977	972,977	972,977	972,977	53,656	-	-	-	-	5,837,862	27
28	LSR3-XP	Schedule A-3k, Page 7, Lines 1 thru 11	1,059,476	1,152,703	1,152,703	1,152,703	1,152,703	1,152,703	93,227	-	-	-	-	6,916,218	28
29			12,964,012	14,030,002	14,030,002	14,030,002	14,030,002	14,030,002	1,065,990	-	-	-	-	84,180,012	29
30															30
31	BTGR Impact - Cost / (Benefit) from the Departure		14,654,808	14,611,798	14,611,798	14,611,798	14,611,798	14,611,798	(43,010)	-	-	-	-	87,670,788	31
32															32
33	BTER Impact														33
34															34
35	Change in Net Fuel and Purchased Power Co:	Schedule A-4a, Page 1, Line 12 X 1000	(24,789,874)	(28,554,552)	(34,004,729)	(39,083,369)	(46,586,800)	(52,609,512)	(2,749,346)	-	-	-	-	(228,378,182)	35
36															36
37	Bundled Revenues-BTER														37
38															38
39	GS	Schedule A-3a, Page 4, Lines 14 thru 24	860	991	932	1,083	1,186	1,292	77	-	-	-	-	6,421	39
40	LGS-1	Schedule A-3b, Page 4, Lines 14 thru 24	267,974	300,508	282,121	328,520	359,796	391,472	14,933	-	-	-	-	1,945,324	40
41	LGS-2S	Schedule A-3c, Page 4, Lines 14 thru 24	697,632	805,032	755,785	880,080	963,865	1,048,718	62,514	-	-	-	-	5,213,626	41
42	LGS-3S	Schedule A-3d, Page 4, Lines 14 thru 24	581,581	654,680	614,626	715,708	783,848	852,852	35,004	-	-	-	-	4,238,299	42
43	LGS-3P	Schedule A-3e, Page 4, Lines 14 thru 24	8,796,220	10,188,304	9,565,027	11,138,061	12,198,444	13,272,316	827,690	-	-	-	-	65,986,062	43
44	LGS-3T	Schedule A-3f, Page 4, Lines 14 thru 24	5,831,211	6,746,374	6,333,660	7,375,274	8,077,427	8,788,512	540,701	-	-	-	-	43,693,159	44
45	LGS-XS	Schedule A-3g, Page 4, Lines 14 thru 24	25,007	29,472	27,667	32,219	35,288	38,391	2,881	-	-	-	-	190,925	45
46	LGS-XP	Schedule A-3h, Page 4, Lines 14 thru 24	5,585,227	6,414,838	6,022,406	7,012,832	7,680,478	8,356,618	469,017	-	-	-	-	41,541,416	46
47	LGS-XT	Schedule A-3i, Page 4, Lines 14 thru 24	6,455,063	7,471,211	7,014,152	8,167,679	8,945,271	9,732,755	601,748	-	-	-	-	48,387,879	47
48	LSR2-3T	Schedule A-3j, Page 4, Lines 14 thru 24	3,369,729	3,819,813	3,586,132	4,175,896	4,573,458	4,976,075	230,457	-	-	-	-	24,731,560	48
49	LSR3-XP	Schedule A-3k, Page 4, Lines 14 thru 24	1,560,373	1,801,409	1,691,207	1,969,339	2,156,826	2,346,698	140,674	-	-	-	-	11,666,526	49
50			33,170,877	38,232,632	35,893,715	41,796,691	45,775,887	49,805,699	2,925,896	-	-	-	-	247,601,197	50
51	Mill Tax Impact (Mill Tax Rate 0 306%)		0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	51
52			33,069,374	38,115,640	35,783,880	41,668,793	45,635,813	49,653,294	2,916,743	-	-	-	-	246,843,537	52
53															53
54	BTER Impact - Cost / (Benefit) of the Departure		8,279,500	9,561,088	1,779,151	2,585,424	(950,987)	(2,956,218)	167,397	-	-	-	-	18,465,355	54
55															55
56															56
57	Other Obligations														57
58															58
59	ERCR Nellis PV Self Build 2016 15 MW	Schedule A-5f, Column (b), Lines 25-34	347,797	312,758	288,301	270,194	252,088	238,744	19,180	-	-	-	-	1,729,062	59
60	ERCR LVC Bundled 274 MW 2015	Schedule A-5f, Column (c), Lines 25-34	949,470	911,866	875,434	840,079	805,731	772,314	61,646	-	-	-	-	5,216,539	60
61	ERCR SunPeak 222 MW 2015	Schedule A-5f, Column (d), Lines 25-34	128,234	117,916	109,766	101,615	95,091	90,193	7,108	-	-	-	-	649,922	61
62	IRP Acq of the 25% Share of Silverhawk	Schedule A-5f, Column (e), Lines 25-34	-	382,784	568,358	545,940	524,220	503,147	40,223	-	-	-	-	2,564,671	62
63			-	-	-	-	-	-	-	-	-	-	-	-	63
64			-	-	-	-	-	-	-	-	-	-	-	-	64
65			-	-	-	-	-	-	-	-	-	-	-	-	65
66			-	-	-	-	-	-	-	-	-	-	-	-	66
67															67
68			1,425,502	1,725,324	1,841,858	1,757,827	1,677,129	1,604,397	128,157	-	-	-	-	10,160,195	68
69															69
70	Cost / (Benefit) of the Departure		$ 24,359,810	$ 25,898,211	$ 18,232,808	$ 18,955,049	$ 15,337,940	$ 13,259,977	$ 252,544	$ -	$ -	$ -	$ -	$ 116,296,338	70
71															71
72															72

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS

Line No	(a)		(b)	(c)	Line No
1					1
2					2
3					3
4					4
5	Net Present Value of One Time Payment (Rate of Return 8 09% per Docket No 14-05004)				5
6	Estimated Departure Date of February 01, 2016				6
7	BTGR Impact	8 09%	$ 67,815,765		7
8	BTER Impact		$ 16,861,205		8
9	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW		$ 1,356,961		9
10	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015		$ 4,062,532		10
11	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015		$ 509,645		11
12	Obligation for ERCR Approved Gen IRP Acq of the 25% Share of Silverhawk		$ 1,885,653		12
13			$ 92,491,761		13
14	Local Government Fee	5%	4,624,588		14
15					15
16	Total Impact Fee		$ 97,116,349		16
17					17
18			Annual Payment		18
19	Annual Payments (Rate of Return 8 09%, per Docket No 14-05004)		For 6 Years	Total	19
20					20
21	BTGR Impact		$ 14,709,669	$ 88,258,014	21
22	BTER Impact		$ 3,657,302	$ 21,943,812	22
23	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW		$ 294,333	$ 1,765,998	23
24	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015		$ 881,189	$ 5,287,134	24
25	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015		$ 110,545	$ 663,270	25
26	Obligation for ERCR Approved Gen IRP Acq. of the 25% Share of Silverhawk		$ 409,010	$ 2,454,060	26
27					27
28			$ 20,062,048	$ 120,372,288	28

ATTACHMENT 8

NEVADA POWER COMPANY d/b/a NV ENERGY
RETAIL OPEN ACCESS ANALYSIS #2 - MGM
IMPACT FEE INCLUDING AVERAGE OF PRODUCTION COST SCENARIOS
(IN THOUSANDS)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
No No		Reference	Feb - Dec 2016	Jan - Dec 2017	Jan - Dec 2018	Jan - Dec 2019	Jan - Dec 2020	Jan - Dec 2021	Jan 2022	2023	2024	2025	2026	Total	Present Value Value 8 09%	Levelized Payment Payment	No No
1	Estimated Charge Necessary to Maintain BTGR Neutrality	Schedule A-2, Line 31	$ 13,784	$ 13,668	$ 13,668	$ 13,668	$ 13,668	$ 13,668	$ (116)	$ -	$ -	$ -	$ -	$ 82,008	$ 63,459	$ 13,765	1
2																	2
3	Estimated Charge Necessary to Maintain BTER Neutrality	Schedule A-2, Line 54	8,194	9,470	1,693	2,486	(1,060)	(3,075)	167	-	-	-	-	17,875	16,411	3,560	3
4																	4
5	*ERCR New Generation Annual Revenue Requirements*																5
6	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW	Schedule A-2, Line 59	348	313	288	270	252	239	19	-	-	-	-	1,729	1,357	294	6
7	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015	Schedule A-2, Line 60	949	912	875	840	806	772	62	-	-	-	-	5,216	4,063	881	7
8	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015	Schedule A-2, Line 61	128	118	110	102	95	90	7	-	-	-	-	650	510	111	8
9	Obligation for acquisition of 25% share of Silverhawk	Schedule A-2, Line 62	-	383	568	546	524	503	40	-	-	-	-	2,564	1,886	409	9
10			-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
11			-	-	-	-	-	-	-	-	-	-	-	-	-	-	11
12			-	-	-	-	-	-	-	-	-	-	-	-	-	-	12
13			-	-	-	-	-	-	-	-	-	-	-	-	-	-	13
14																	14
15			$ 23,403	$ 24,864	$ 17,202	$ 17,912	$ 14,285	$ 12,197	$ 179	$ -	$ -	$ -	$ -	$ 110,042	$ 87,686	$ 19,020	15
16																	16
17	Local Government Fee														4,384		17
18																	18
19															$ 92,070		19
20																	20
21																	21
22		The 6-year impact is detrimental to the Company's system, therefore, the impact fee is														$ 92,070	22
23																	23
24																	24
25		Amounts in parentheses indicate that the change in costs or revenues are negative If the Total Impact is a negative amount, there is a benefit for the customer to depart, if the Total Impact is a positive amount , there is a cost for the customer															25
26		to depart															26

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Line No	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	Line No
	BTGR Impact	Schedule Reference	Feb - Dec 2016	Jan - Dec 2017	Jan - Dec 2018	Jan - Dec 2019	Jan - Dec 2020	Jan - Dec 2021	Jan 2022	2023	2024	2025	2026	Total	
1	Bundled Revenues-BTGR														1
2															2
3	GS	Schedule A-3a, Page 4, Lines 26 thru 36	1,246	1,381	1,381	1,381	1,381	1,381	135	-	-	-	-	$ 8,286	3
4	LGS-1	Schedule A-3b, Page 4, Lines 26 thru 36	156,379	174,279	174,279	174,279	174,279	174,279	17,900	-	-	-	-	1,045,674	4
5	LGS-2S	Schedule A-3c, Page 4, Lines 26 thru 36	641,205	671,962	671,962	671,962	671,962	671,962	30,757	-	-	-	-	4,031,772	5
6	LGS-3S	Schedule A-3d, Page 4, Lines 26 thru 36	719,390	745,821	745,821	745,821	745,821	745,821	26,431	-	-	-	-	4,474,926	6
7	LGS-3P	Schedule A-3e, Page 4, Lines 26 thru 36	7,724,189	8,029,251	8,029,251	8,029,251	8,029,251	8,029,251	305,062	-	-	-	-	48,175,506	7
8	LGS-3T	Schedule A-3f, Page 4, Lines 26 thru 36	3,233,768	3,309,289	3,309,289	3,309,289	3,309,289	3,309,289	75,521	-	-	-	-	19,855,734	8
9	LGS-XS	Schedule A-3g, Page 4, Lines 26 thru 36	15,499	16,497	16,497	16,497	16,497	16,497	998	-	-	-	-	98,982	9
10	LGS-XP	Schedule A-3h, Page 4, Lines 26 thru 36	5,617,996	5,835,518	5,835,518	5,835,518	5,835,518	5,835,518	217,522	-	-	-	-	35,013,108	10
11	LGS-XT	Schedule A-3i, Page 4, Lines 26 thru 36	4,741,605	4,902,473	4,902,473	4,902,473	4,902,473	4,902,473	160,868	-	-	-	-	29,414,838	11
12	LSR2-3T	Schedule A-3j, Page 4, Lines 26 thru 36	3,333,340	3,471,127	3,471,127	3,471,127	3,471,127	3,471,127	137,787	-	-	-	-	20,826,762	12
13	LSR3-XP	Schedule A-3k, Page 4, Lines 26 thru 36	1,361,835	1,411,834	1,411,834	1,411,834	1,411,834	1,411,834	49,999	-	-	-	-	8,471,004	13
14			27,546,452	28,569,432	28,569,432	28,569,432	28,569,432	28,569,432	1,022,980	-	-	-	-	171,416,592	14
15															15
16	Less Unbundled Revenues Transmission & Distribution Only Service Revenue														16
17															17
18	GS	Schedule A-3a, Page 7, Lines 1 thru 11	1,215	1,326	1,326	1,326	1,326	1,326	111	-	-	-	-	7,956	18
19	LGS-1	Schedule A-3b, Page 7, Lines 1 thru 11	136,054	147,327	147,327	147,327	147,327	147,327	11,273	-	-	-	-	883,962	19
20	LGS-2S	Schedule A-3c, Page 7, Lines 1 thru 11	336,412	364,522	364,522	364,522	364,522	364,522	28,110	-	-	-	-	2,187,132	20
21	LGS-3S	Schedule A-3d, Page 7, Lines 1 thru 11	395,532	427,696	427,696	427,696	427,696	427,696	32,164	-	-	-	-	2,566,176	21
22	LGS-3P	Schedule A-3e, Page 7, Lines 1 thru 11	4,209,554	4,574,212	4,574,212	4,574,212	4,574,212	4,574,212	364,658	-	-	-	-	27,445,272	22
23	LGS-3T	Schedule A-3f, Page 7, Lines 1 thru 11	1,263,760	1,364,126	1,364,126	1,364,126	1,364,126	1,364,126	100,366	-	-	-	-	8,184,756	23
24	LGS-XS	Schedule A-3g, Page 7, Lines 1 thru 11	8,574	9,431	9,431	9,431	9,431	9,431	857	-	-	-	-	56,586	24
25	LGS-XP	Schedule A-3h, Page 7, Lines 1 thru 11	2,580,990	2,791,903	2,791,903	2,791,903	2,791,903	2,791,903	210,913	-	-	-	-	16,751,418	25
26	LGS-XT	Schedule A-3i, Page 7, Lines 1 thru 11	2,044,524	2,215,179	2,215,179	2,215,179	2,215,179	2,215,179	170,655	-	-	-	-	13,291,074	26
27	LSR2-3T	Schedule A-3j, Page 7, Lines 1 thru 11	2,039,836	2,195,357	2,195,357	2,195,357	2,195,357	2,195,357	155,521	-	-	-	-	13,172,142	27
28	LSR3-XP	Schedule A-3k, Page 7, Lines 1 thru 11	745,635	810,331	810,331	810,331	810,331	810,331	64,696	-	-	-	-	4,861,986	28
29			13,762,086	14,901,410	14,901,410	14,901,410	14,901,410	14,901,410	1,139,324	-	-	-	-	89,408,460	29
30															30
31	BTGR Impact - Cost / (Benefit) from the Departure		13,784,366	13,668,022	13,668,022	13,668,022	13,668,022	13,668,022	(116,344)	-	-	-	-	82,008,132	31
32															32
33	BTER Impact														33
34															34
35	Change in Net Fuel and Purchased Power Co:	Schedule A-4a, Page 1, Line 12 X 1000	(24,789,874)	(28,554,552)	(34,004,729)	(39,083,369)	(46,586,800)	(52,609,512)	(2,749,346)	-	-	-	-	(228,378,182)	35
36															36
37	Bundled Revenues-BTER														37
38															38
39	GS	Schedule A-3a, Page 4, Lines 14 thru 24	644	763	717	833	913	993	77	-	-	-	-	4,940	39
40	LGS-1	Schedule A-3b, Page 4, Lines 14 thru 24	182,394	209,119	196,325	228,612	250,378	272,421	14,933	-	-	-	-	1,354,182	40
41	LGS-2S	Schedule A-3c, Page 4, Lines 14 thru 24	697,632	805,032	755,785	880,080	963,865	1,048,718	62,514	-	-	-	-	5,213,626	41
42	LGS-3S	Schedule A-3d, Page 4, Lines 14 thru 24	581,581	654,680	614,626	715,708	783,848	852,852	35,004	-	-	-	-	4,238,299	42
43	LGS-3P	Schedule A-3e, Page 4, Lines 14 thru 24	8,796,220	10,188,304	9,565,027	11,138,061	12,198,444	13,272,316	827,690	-	-	-	-	65,986,062	43
44	LGS-3T	Schedule A-3f, Page 4, Lines 14 thru 24	5,831,211	6,746,374	6,333,660	7,375,274	8,077,427	8,788,512	540,701	-	-	-	-	43,693,159	44
45	LGS-XS	Schedule A-3g, Page 4, Lines 14 thru 24	25,007	29,472	27,667	32,219	35,288	38,391	2,881	-	-	-	-	190,925	45
46	LGS-XP	Schedule A-3h, Page 4, Lines 14 thru 24	5,585,227	6,414,838	6,022,406	7,012,832	7,680,478	8,356,618	469,017	-	-	-	-	41,541,416	46
47	LGS-XT	Schedule A-3i, Page 4, Lines 14 thru 24	6,455,063	7,471,211	7,014,152	8,167,679	8,945,271	9,732,755	601,748	-	-	-	-	48,387,879	47
48	LSR2-3T	Schedule A-3j, Page 4, Lines 14 thru 24	3,369,729	3,819,813	3,586,132	4,175,896	4,573,458	4,976,075	230,457	-	-	-	-	24,731,560	48
49	LSR3-XP	Schedule A-3k, Page 4, Lines 14 thru 24	1,560,373	1,801,409	1,691,207	1,969,339	2,156,826	2,346,698	140,674	-	-	-	-	11,666,526	49
50			33,085,081	38,141,015	35,807,704	41,696,533	45,666,196	49,686,349	2,925,696	-	-	-	-	247,008,574	50
51	Mill Tax Impact (Mill Tax Rate 0 306%)		0 99694	0 99694	0.99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	0 99694	51
52			32,983,841	38,024,303	35,698,132	41,568,942	45,526,457	49,534,309	2,916,743	-	-	-	-	246,252,728	52
53															53
54	BTER Impact - Cost / (Benefit) of the Departure		8,193,967	9,469,751	1,693,403	2,485,573	(1,060,343)	(3,075,203)	167,397	-	-	-	-	17,874,546	54
55															55
56															56
57	Other Obligations														57
58															58
59	ERCR Nellis PV Self Build 2016 15 MW	Schedule A-5f, Column (b), Lines 25-34	347,797	312,758	288,301	270,194	252,088	238,744	19,180	-	-	-	-	1,729,062	59
60	ERCR LVC Bundled 274 MW 2015	Schedule A-5f, Column (c), Lines 25-34	949,470	911,866	875,434	840,079	805,731	772,314	61,646	-	-	-	-	5,216,539	60
61	ERCR SunPeak 222 MW 2015	Schedule A-5f, Column (d), Lines 25-34	128,234	117,916	109,766	101,615	95,091	90,193	7,108	-	-	-	-	649,922	61
62	IRP Acq of the 25% Share of Silverhawk	Schedule A-5f, Column (e), Lines 25-34	-	382,784	568,358	545,940	524,220	503,147	40,223	-	-	-	-	2,564,671	62
63			-	-	-	-	-	-	-	-	-	-	-	-	63
64			-	-	-	-	-	-	-	-	-	-	-	-	64
65			-	-	-	-	-	-	-	-	-	-	-	-	65
66			-	-	-	-	-	-	-	-	-	-	-	-	66
67															67
68			1,425,502	1,725,324	1,841,858	1,757,827	1,677,129	1,604,397	128,157	-	-	-	-	10,160,195	68
69															69
70	Cost / (Benefit) of the Departure		$ 23,403,835	$ 24,863,098	$ 17,203,284	$ 17,911,422	$ 14,284,808	$ 12,197,216	$ 179,210	$ -	$ -	$ -	$ -	$ 110,042,873	70
71															71
72															72

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Line No	(a)		(b)	(c)	Line No
1					1
2					2
3					3
4					4
5	Net Present Value of One Time Payment (Rate of Return 8 09% per Docket No 14-05004)				5
6	Estimated Departure Date of February 01, 2016				6
7	BTGR Impact	8 09%	$ 63,458,694		7
8	BTER Impact		$ 16,411,217		8
9	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW		$ 1,356,961		9
10	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015		$ 4,062,532		10
11	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015		$ 509,645		11
12	Obligation for ERCR Approved Gen IRP Acq of the 25% Share of Silverhawk		$ 1,885,653		12
13			$ 87,684,702		13
14	Local Government Fee	5%	4,384,235		14
15					15
16	Total Impact Fee		$ 92,068,937		16
17					17
18			Annual Payment		18
19	Annual Payments (Rate of Return 8 09%, per Docket No 14-05004)		For 6 Years	Total	19
20					20
21	BTGR Impact		$ 13,764,593	$ 82,587,558	21
22	BTER Impact		$ 3,559,697	$ 21,358,182	22
23	Obligation for ERCR Approved Gen ERCR Nellis PV Self Build 2016 15 MW		$ 294,333	$ 1,765,998	23
24	Obligation for ERCR Approved Gen ERCR LVC Bundled 274 MW 2015		$ 881,189	$ 5,287,134	24
25	Obligation for ERCR Approved Gen ERCR SunPeak 222 MW 2015		$ 110,545	$ 663,270	25
26	Obligation for ERCR Approved Gen IRP Acq of the 25% Share of Silverhawk		$ 409,010	$ 2,454,060	26
27					27
28			$ 19,019,367	$ 114,116,202	28

ATTACHMENT 9

MGM - Lump Sum Analysis

MGM 6 -year exit fee (NPV)	155,236,075
Annual Revenue Requirement	25,872,679

	RS	LGS-2S	LGS-3P
Percent Allocated to Class (1)	41.02%	9.15%	8.92%
Annual Portion to Class	10,611,938	2,366,574	2,308,360
Annual kWh (1)	6,990,266,000	2,342,404,000	2,463,370,000
Estimated Change to Rate (per kWh)	$0.0015	$0.0010	$0.0009
Average Monthly Use (kWh) (1)	1,141	162,356	1,682,630
Estimated Change to Monthly Bill	$1.73	$164.03	$1,576.75

MGM - Non-Bypassable Rate Analysis

MGM 6 -year exit fee (NPV)	89,222,000
Annual Revenue Requirement	14,870,333

	RS	LGS-2S	LGS-3P
Percent Allocated to Class (1)	41.02%	9.15%	8.92%
Annual Portion to Class	6,099,216	1,360,189	1,326,731
Annual kWh (1)	6,990,266,000	2,342,404,000	2,463,370,000
Estimated Change to Rate (per kWh)	$0.0009	$0.0006	$0.0005
Average Monthly Use (kWh) (1)	1,141	162,356	1,682,630
Estimated Change to Monthly Bill	$1.00	$94.28	$906.24

Notes:

1. Statement O, Certification Filing Docket No. 14-05004.