•

•

•

18-12018

Public Utilities Commission of Nevada
Electronic Filing
Submitted: 3/1/2019 11:33:25 AM

Reference: 48a5b9c9-2035-4aff-b780-9769e4585e61
Reference:
Filed For: Staff Counsel Division

In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s TinaRoberts

By electronically filing the document(s),
the filer attests to the authenticity of the electronic signature(s) contained therein.

This filing has been electronically filed and deemed to be signed by an authorized agent or
representative of the signer(s) and
Staff Counsel Division

STEVE SISOLAK
Governor

STATE OF NEVADA

PUBLIC UTILITIES COMMISSION

March 1, 2019

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

RE: <u>Docket No. 18-12018 – Staff's Final Impact Analysis</u>

Dear Ms. Osborne:

Please find attached the Regulatory Operations Staff's ("Staff") Final Impact Analysis in the above-referenced Docket. Pursuant to the Commission's Procedural Order dated January 30, 2019, Staff has also provided in executable format its confidential calculations/workpapers underseal.

If you have any questions, please contact me directly.

Sincerely,

Samuel S. Crano
Assistant Staff Counsel

SSC/tmr
Attachment
cc/Parties of Record

STAFF'S FINAL IMPACT ANALYSIS for

MEI-GSR HOLDINGS LLC d/b/a GRAND SIERRA RESORT" ("GSR") NRS CHAPTER 704B NORTHERN NEVADA DEPARTURE APPLICATION

DOCKET NO. 18-12018

SUMMARY

The total load that GSR proposes to move from bundled retail electric service represents approximately 0.51 percent over the 3 year analysis period of Sierra Pacific Power Company d/b/a NV Energy's ("SPPC's") annual energy sales, and therefore, materially impacts SPPC's future revenue and costs to remaining SPPC customers. Based upon revised calculations and production cost information the Regulatory Operations Staff ("Staff") of the Public Utilities Commission of Nevada ("Commission") requested from SPPC and received on February 26, 2019 ("4th Revised Requested Calculations"), Staff performed its final analysis of the impact of GSR's proposed departure of approximately 8.0 mega-watts ("MW") of peak electric consumption. Staff's final impact fee is approximately **<u>$2.122 million for a 3-year</u>** analysis period utilizing the lump-sum methodology, including the Demand Side Management ("DSM") recapture and local Government fees and on a net-present value ("NPV") basis. Table 1, below, provides a summary of the impact fee analyses for the three-year analysis period. The impact fees contained in Table 1 include the local government fee, and GSR's DSM Recapture Payment of $364,000, but does not credit GSR with off-system sales ("OSS") that theoretically could result from the departure of its load from SPPC's system, which is discussed further below.

Table 1 - GSR Impact Fee (No Off-System Sales)		
	3-year	
	Nominal	Net Present Value
Adjusted 4th Revised Calculation	$1,859,000	$1,657,000
DSM Recapture Payment	$364,000	$364,000
Subtotal	$2,223,000	$2,021,000
Local Government Fee	$111,000	$101,000
Total Impact Fee	$2,234,000	$2,122,000

BACKGROUND

On January 4, 2019, Staff directed SPPC, pursuant to Nevada Administrative Code ("NAC") 704B.350, to perform 704B impact calculations utilizing both the lump sum and non-bypassable rate methodologies to determine the impact that a departure of GSR's load would have on remaining customers, as well as on SPPC. A copy of Staff's Directive Document to SPPC is provided as Attachment 1. Attachment 1 lays out the key inputs and analysis criteria that Staff directed SPPC to use in performing the calculations and production cost simulations, and were discussed with GSR, SPPC and the Attorney General's Bureau of Consumer Protection ("BCP") at a meeting held on December 5, 2018. On February 1, 2019, SPPC provided Staff with its initial calculations. On February 5, 2019, SPPC provided Staff with revised calculations after correcting an error regarding the BTER calculation which was discovered by Staff. On February 6, 2019, SPPC provided Staff with a 2nd revised calculation after correcting errors regarding the REPR and TRED calculations which were discovered by Staff ("2nd Revised Requested Calculation"). Further, Staff adjusted the numbers in the 2nd Revised Requested Calculation to remove the twelve months of included Energy Efficiency ("EE") program and implementation costs, as the departure date, as requested in GSR's Application, is October 1, 2019. On February 8, 2019, Staff provided GSR, BCP, Tenaska Power Services Co., ("Tenaska")[1] and SPPC a copy of Staff's Initial Impact Analysis pursuant to NAC 704B.350(1). On February 19, 2019, SPPC provided Staff with a 3rd revised calculation after correcting an error regarding the year 2028 BTER fee calculation discovered by Staff. On February 20, 2019, Staff met with GSR, the BCP and SPPC to discuss Staff's Initial Impact Analysis pursuant to NAC 704B.350(2).

NAC 704B.350(2) provides for a collaborative process in which the parties of record meet to discuss the results of Staff's Initial Impact Analysis and exchange information, including, without limitation, suggested additions, modifications or deletions to Staff's Initial Impact Analysis. At the meeting on February 20, 2019, Staff provided its observations to the group regarding that the ratio of unbundled to bundled revenues in the spreadsheet calculations for the GSR's impact fee was different than what Staff had observed in prior calculations which may indicate an error. Additionally, Staff provided its observations to the group regarding a marked difference in OSS results between the run for recent southern Nevada Revised Statute ("NRS") 704B applicants and the run for the GSR. GSR, Staff and BCP had discussions regarding the PROMOD modeling of off-system sales and directed those questions to NPC. However, other than NPC's legal counsel, no other NPC personnel attended the meeting. Therefore, the parties of record set up an additional meeting with the appropriate NPC personnel and that teleconference took place on February 25, 2019. On February 26, 2019, as a result of the February 25, 2019, teleconference, SPPC provided Staff and the other parties with a 4th Revised Requested Calculation after making a revision that corrected the error identified by Staff that related to the unbundled to bundled revenues, however, SPPC found no correction was necessary relating to the OSS anomaly. Staff again adjusted the 4th Revised Requested Calculations to remove the EE charge as outlined below, and Staff believes that the Adjusted 4th Revised Requested Calculation, with the inclusion of SLS' DSM Recapture Payment, constitutes a

---

1 The Commission issued an Order approving Tenaska's Petition for Leave to Intervene on January 30, 2019.

reasonable estimate of the impact of GSR's departure under the provisions of NRS Chapter 704B.[2]

704B LUMP-SUM IMPACT METHODOLOGY CALCULATION

Staff's recommended initial impact fee of approximately $2.122 million for a 3-year analysis period consists of the amount calculated in the 4th Revised Requested Calculation, as adjusted, plus Staff's calculated DSM Recapture Fee and the local government fee, but does not give credit to GSR for potential off-system sales. The Adjusted 4th Revised Requested Calculation utilizes the lump-sum rate methodology. The calculation, as adjusted, shows the 3-year impact of GSR's load departing to be approximately $1.657 million on a net present value basis. The summary sheet from the 4th Revised Requested Calculation is attached hereto as Attachment 2 and the separate categories that make up the estimated impact fee are:

1) BTGR Impact: This is the BTGR revenue impact that SPPC will experience, and remaining customers will be burdened with, once GSR's load leaves bundled retail service. Upon exit, GSR will pay only transmission (pursuant to SPPC's OATT) and distribution charges (pursuant to SPPC's Distribution-Only Service Rider ("DOS") Tariff). GSR will no longer contribute to the revenue requirement related to the generation assets which were, in part, built to serve GSR's load.

The net present value of the BTGR portion of GSR's 3-year impact fee is $1.453 million. This impact is caused by SPPC receiving less revenue from GSR over the analysis timeframe. SPPC's Transmission and Distribution ("T&D") rates account for approximately 57.4 percent of BTGR revenues, leaving a revenue shortfall of the remaining 42.6 percent for SPPC and other customers to absorb.[3] Tab "Summary (A-2)" line thirteen of the Requested Calculation outlines the BTGR revenue shortfall that results.

2) BTER Impact: This is the estimated impact that will result to fuel and purchase power costs as a result of GSR's load being removed from the total load that SPPC is required to serve. The BTER impact was determined by performing two PROMOD production cost simulations: one simulation with GSR's load in the load forecast ("Base Case") and one with GSR's load removed ("Change Case"), both cases with off-system sales disabled. Staff's BTER impact analyses excluded all of the placeholder resources contained in SPPC's joint IRP filing, Docket No. 18-06003, 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 basis of the BTER impact resulting from GSR's load departing

---

2 Staff reviewed the PROMOD output files "GSR Base Case.REP" and "GSR Change Case.REP" provided by SPPC and has no reason to believe that SPPC did not use the inputs as directed by Staff in the Directive Document.

3 Up until the correction made in the fourth revision of the requested calculation, this percentage was 63.7% and 36.3%, much different than that shown in the requested calculations received by Staff related to prior applications. For example, as can be seen in Staff's Final Impact Analysis filed on December 7, 2018, in Docket No. 18-08007, the percentages shown in the calculations in that Docket are 54.2% and 45.8%, respectively. Staff will evaluate the percentages and their impact on the overall impact fee in the course of Staff's continuing verification efforts.

SPPC's bundled retail service. GSR's net present value BTER 3-year impact is a credit of $170,000.00.

3) Variable Operations & Maintenance ("O&M") Costs: As discussed above, once GSR's load departs bundled retail service, SPPC'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, GSR is paying for a fixed amount of variable O&M costs in the BTGR portion of the exit fee calculation, and therefore should be given credit for the reduction in variable O&M costs that are incurred when GSR's load is removed. The O&M credit is estimated for the 3-year impact fee, on a net present value basis, to be approximately $202,000.00.

4) Credit for the Apple Nevada Green Rider ("NGR") contracts: This credit represents GSR's load ratio share of the Apple NGR contracts which is estimated for the 3-year impact fee to be $12,000.00, on a net present value basis.

5) Obligation for Existing and Future Regulatory Assets/Liabilities: This cost represents GSR's Marginal Cost of Service Study Percentage Share of the Valmy depreciation expenses that were deferred in Docket No. 16-06006, the Ely Energy Center stranded costs and other misc. deferred costs that are not currently in current rates. GSR's 3-year load ratio share of the Regulatory Asset costs is $37,000.00 on a net present value basis.

6) October 2019 – September 2020 EE Payment: This is the cost associated with operating the DSM programs that have been approved by the Commission as well as any financial disincentive due to the DSM programs. New DSM program and implementation rates would go into effect on October 1, 2019, when GSR departs SPPC's bundled retail service. Therefore, GSR's EE program and implementation costs are zero. The rates set in October 2019, and in following years, will not be applicable to GSR as they will no longer be a customer of SPPC and, therefore, not eligible to participate in DSM programs and, as such, should not be assessed any future energy efficiency costs.[4]

7) Renewable Energy Program Rate ("REPR"): This is the rate component associated with program administration costs and providing rebates under the solar and wind renewable generation programs mandated by NRS chapter 701B. GSR's 3-year share of the REPR cost on a net present value basis is approximately $434,000.00.

8) Temporary Renewable Energy Trust ("TRED"): This is the rate component associated with the Temporary Renewable Energy Trust fund. GSR's 3-year share of the TRED cost on a net present value basis is approximately $117,000.00.

9) DSM Recapture Fee: This is the amount of any DSM incentives that were provided by SPPC to GSR over the past 5 years, based upon the remaining program life associated with each incentive should GSR choose to depart retail service under the provisions of NRS Chapter 704B.

[4] The 4th Revised Requested Calculations, Attachment 2, do show this line item being $73,000 on a net present value basis, however, as explained above, Staff believes this line item should be zero and therefore Staff adjusted the requested calculations to reflect a zero amount when calculating Staff's recommended impact fee.

Staff's initial analysis of the DSM incentives paid by SPPC to GSR over the past 5 years indicates that GSR should refund approximately $364,000.00 of the incentives it received. This amount was added to the 4th Revised Requested Calculations as a separate line item. The summary sheets of the workpapers associated with GSR's DSM Recapture Payment are provided in Attachment 3.[5]

10) Local Government Fees: This cost represents the 5 percent Local Government Franchise Fee that SPPC collects on revenue generated. This cost is much like a sales tax, and is derived by simply multiplying the sum of the other cost categories by 5 percent. The local government fee that needs to be collected is calculated to be $101,000.00 for the 3-year net present value analysis.

11) Off-System Sales: Staff is not including a credit in the Impact Fee for the utility's forecasted off-system sales of energy and/or capacity due to GSR's planned departure from bundled retail electric service. Staff understands that the Commission has granted an off-system sales credit has been provided in some prior NRS Chapter 704B impact analyses. Underlying this credit is the assumption that NV Energy's generation resources, which previously served the eligible customer departing bundled retail electric service with generation from NV Energy, are now available for sale to other entities in the wholesale market. However, this assumption must be evaluated based on the changing circumstances pursuant to NRS Chapter 704B. Staff has not included an off-system sales credit in the present analysis for a number of reasons, including, but not limited to: a) Staff believes that, given the number and rate of filing of 704B Applicants who have already departed bundled retail electric service, and existing and new customers considering departing bundled retail electric service, it is not reasonable or practical to assume that NV Energy can continue to make more and more off-system sales from the growing amount of generation assets/surplus capacity that is left behind when a customer leaves bundled retail electric service. There is a limit to the marketplace in which these off-system sales can be made; b) Staff has seen no evidence that the sales forecasted by PROMOD are actually occurring; c) PROMOD's calculation is strictly mathematical, and assumes a willing counterparty. Staff does not believe those counterparties exist based on the fact that the Applicant is leaving bundled service in order to purchase its capacity and energy needs in the open market because NV Energy's costs are too high and market prices are so much less expensive; it is somewhat illogical to assume NV Energy would be able to sell the surplus energy and capacity that result given the Applicant's departure into the same market that the Applicant is stating has lower cost resources; and d) Staff sees the lowering price of renewable energy, as evidenced by the 1,000 MW of new solar contracts and storage approved in Docket No. 18-06003, which are priced below NV Energy's current avoided cost, as confirmation that it would be illogical for any counterparty in the marketplace to purchase NV Energy's remaining fossil fuel generation when such cheaper renewable assets are available in the same marketplace. As such, Staff does not believe that NV Energy can continue to sell increasing amounts of its fossil fuel powered energy and capacity into and increasingly saturated market, and does not believe the Applicant should

---

5 While the summary sheets are public, the entirety of the workpapers, also served on the parties and filed with the Commission do contain some confidential information, and are, thus, filed under seal.

be credited for such speculative sales, placing the entire risk of said speculative sales on remaining retail ratepayers. However, for informational purposes, a calculated off-system sales credit related to GSR's Impact Fee would result in a credit of $177,000, or a total impact fee inclusive of off-system sales which would be approximately $1.945 million. To be clear, Staff does not believe it would be in the public interest to include an off-system sales credit in the impact analysis..

NON-BYPASSABLE RATES

Two legislatively-mandated charges must also be assessed against GSR's load, namely:

- The IS-2 Irrigation Rate Program pursuant to NRS 704.225 for which all customers are required to pay (including distribution and transmission-only customers); and
- The Economic Development Rate Program pursuant to NRS 704.7875 for which all customers are required to pay (including distribution and transmission-only customers).

Additionally, GSR will still be required, pursuant to NRS 704B.360, to pay the Commission's annual assessment pursuant to NRS 704.033 and the local government franchise fee, via all sales made by its provider of new electric resources.

STAFF'S PROPOSED MODIFICATIONS AND/OR CONCERNS

To date, Staff has carefully reviewed each iteration of the calculations provided by SPPC and believes it has identified all significant outstanding issues with the calculations, and subsequently, worked diligently with SPPC and the other parties to have those issues corrected and addressed in the adjusted 4th Revised Requested Calculations used for this final analysis.

Staff has identified Excess Accumulated Deferred Income Tax ("EDIT") as an issue that cannot be properly and fairly valued at this time in the adjusted 4th Revised Requested Calculation, but believes that GSR should be responsible for, or be entitled to, a cost or credit. As part of future proceedings, Staff recommends that the Commission determine GSR's appropriate share of the costs and/or benefits associated with EDIT. On October 8, 2018, the Commission issued an order in Consolidated Docket Nos. 18-02010, 18-02011, and 18-02012 directing SPPC to record any EDIT as a regulatory liability until SPPC's next general rate case, wherein the Commission will determine the allocation of and amortization of EDIT. Staff therefore, recommends that any adjustments related to EDIT and its applicability to GSR be addressed in a separate proceeding that may take place after GSR's departure from bundled electric retail service.

Additionally, Staff has identified potential remaining Valmy Costs as an issue that cannot be properly and fairly valued at this time in the adjusted 4th Revised Requested Calculation, but believes that GSR should be allocated its appropriate share of the costs and/or benefits associated with Valmy remaining net book value at the time such remaining net book value costs are approved by the Commission and added into rates. GSR should also be allocated its appropriate share of any Commission-approved Valmy decommissioning and remediation costs until such costs are fully recovered. The mechanism to collect GSR's appropriate share of the Commission-approved Valmy remaining net book value costs and decommissioning and remediation costs will be determined in a general rate case in which the Commission approves such costs. As such, Staff believes such a placeholder provision necessary.

AVAILABLE TRANSMISSION IMPORT CAPACITY

Staff is aware that SPPC has taken the position that there is no available firm import capacity to allow any further NRS 704B customers to depart retail service in northern Nevada without new transmission being constructed. Staff is further aware that SPPC filed a late-filed exhibit in Docket No. 18-08007 to support that position. Staff is still reviewing that information and the issuance of this impact analysis should not be construed to presume that Staff is taking any position, at this time, regarding the availability of firm transmission import capacity for the GSR to reserve upon departing bundled retail service.

ATTACHMENT 1

DIRECTIVE DOCUMENT

Staff's NRS Chapter 704B Exit Impact Analysis

Docket No. 18-12018 – MEI-GSR Holdings, LLC d/b/a Grand Sierra Resort's ("GSR") Northern Nevada Exit Application ("Exit Application")

As required by Nevada Administrative Code ("NAC") 704B.350, the Regulatory Operations Staff ('Staff") of the Public Utilities Commission of Nevada ("Commission") is requesting Sierra Pacific Power Company d/b/a NV Energy ("SPPC") perform the following calculations/PROMOD analyses in order for Staff to estimate the potential impacts of the departure of GSR's load on the electric utility and its remaining customers. The analyses using the Non-Bypassable and the Lump-Sum Rate Methodologies are divided into categories as follows: 1) the Base Tariff Energy Rate ("BTER")/PROMOD analysis; and 2) the Base Tariff General Rate ("BTGR") analysis. The key inputs and assumptions that Staff is requesting be used for each category are described herein below and were discussed during a meeting with all parties on December 5, 2018. If SPPC has any questions regarding Staff's requested analyses, please contact Staff immediately. Please provide the results of these analyses on or before **January 23, 2019**, or as soon thereafter as practicable. When the results are provided to Staff, please include all workpapers, including any macros or Excel files used to extract data from the PROMOD output reports, and PROMOD output report files, including workpapers showing the yearly capacity credits (if any) and off-system sales that were given as a result of GSR's load departing and the variable operations and maintenance savings SPPC will accrue as a result of GSR's load departing due to SPPC's generation units potentially operating less frequently.

ANALYSES REQUESTED BY STAFF

BTER/PROMOD ANALYSIS

- Use SPPC's PROMOD software to perform a ten-year production cost simulation from October 1, 2019, through September 30, 2029 (the "ten-year analysis period"). Staff is requesting takeoff points for ***each year*** of the analysis period.
- Perform two sets of production cost simulations under the guidelines provided below: a) Base Case Expansion Plan; and b) Exit Impact or "Change Case" Plan.
  a) Base Case Expansion Plan
     - Use NPC's and SPPC's ("SPPC" together with NPC, "the Companies") 2019-2021 Action Plan in the Companies' joint 2019-2038 Integrated Resource Plan ("IRP") as approved by the Commission in its Order in Docket No. 18-06003, which includes six solar photovoltaic ("PV") projects Purchase Power Agreement ("PPA").

- Use the base load, fuel and purchase power forecast with the mid carbon assumption.
- Exclude all energy and capacity needs associated with the placeholder resources from the Commission approved plan and assume all energy and capacity needs are fulfilled with market purchases at the prices contained in the fuel and purchase power forecast discussed above.
- Because they have pending Applications or LOIs pursuant to NRS Chapter 704B before the Commission, remove the loads of the following entities: 1) Station Casinos LLC's Application in Docket No. 18-06008, 2) Golden Road Motor Inn, Inc. d/b/a Atlantis Casino Resort Spa's Application in Docket No. 18-08007, 3) Georgia-Pacific Gypsum LLC's Application in Docket No 18-09015, 4) Boyd Gaming Corporation's Application in Docket No. 18-11039, 5) Gaughan South LLC, dba South Point's Application in Docket No. 18-12003, 6) Las Vegas Resort Holding LLC dba SLS Las Vegas' Application in Docket No. 18-12019 and, 7) [redacted] (referred to as "Eligible Customer X") who submitted their LOI on December 17, 2018.

b) Change Case Plan
   - The load forecast for the Change Case Plan is the Base Case Expansion Plan's (above) load forecast with GSR's factored load removed. Because PROMOD typically dispatches on a whole MW basis, and the GSR's load is small compared to the combined hourly loads of the combined utilities (SPPC and NPC), scale up all GSR load inputs into SPPC's PROMOD software by a factor of five in order to reduce the effect of rounding and other potential materiality issues, then round to the nearest MW, and finally factor down the results of the production cost simulation by that same factor of five. For the Change Case, use the GSR's actual billing determinants during the 12-month period from October 1, 2017, through September 30, 2018 ("12-month test period"), for each service location identified in Exhibit A to GSR's Application.
   - The 12-month test period incorporates any demand side management programs implemented to date.
   - Use October 1, 2019, as the Departure Date for the analyses. The ten-year analysis period is therefore October 1, 2019, through September 30, 2029, with takeoff points for ***each year.***
   - Should it later be determined during the course of this proceeding that there are additions or reductions to any eligible customer's load in the study period, Staff will linearly adjust the impact analysis results to account for any such minor additions or reductions.

c) Both the Base Case Expansion Plan and Change Case Plan
   - Perform the production costs simulations under two different scenarios: i) with external sales turned off; and ii) with external sales turned on. At this point Staff