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18-12018

Public Utilities Commission of Nevada
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NV Energy

March 15, 2019

Ms. Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East William Street
Carson City, Nevada 89701-3109

RE: Docket No. 18-12018 – NRS 704B Application of MEI – GSR Holdings LLC d/b/a Grand Sierra Resort

Dear Ms. Osborne:

Enclosed please find the Sierra Pacific Power Company d/b/a NV Energy's ("Company") Alternative Analysis for the above referenced docket. This filing is made pursuant to Nevada Administrative Code section 704B.350(4), as well as Paragraph 10(b) of the Public Utilities Commission of Nevada's ("Commission") Procedural Order dated January 30, 2019. Copies of the following electronic workpapers will be delivered to Commission and the parties of record:

- NPC GSR Alternative Analysis NO OSS 14-year summary page (confidential)
- NPC GSR Alternative Analysis NO OSS 14-year (confidential)
- GSR Workpaper 1
- GSR Workpaper 2 (confidential)

In addition, portions of the alternative analysis narrative and the summaries contain confidential customer specific information and are being provided under seal. The Company asks that this information be kept confidential for a period of five (5) years. It may be destroyed or returned at the end of that period, as is most convenient for the Commission.

Should you have any questions regarding this filing, please contact me at (702) 402-5697 or dbrooks@nvenergy.com.

Respectfully submitted,

/s/ Douglas Brooks
Douglas Brooks
Senior Attorney

DOCKET NO. 18-12018
SIERRA PACIFIC POWER COMPANY D/B/A NV
ENERGY ALTERNATIVE IMPACT ANALYSIS

Pursuant to Nevada Administrative Code Section 704B.350(4), Sierra Pacific Power Company d/b/a/ NV Energy ("Sierra" or the "Company") hereby submits its alternative analysis to the Regulatory Operations Staff's ("Staff") final impact analysis for MEI-GSR Holdings LLC d/b/a Grand Sierra Resort ("GSR" or the "Applicant"). Staff filed its analysis with the Public Utilities Commission of Nevada ("Commission") on March 1, 2019.

I. Summary

There is no question that circumstances today are far different than they were when the Nevada Legislature adopted Nevada Revised Statutes ("NRS") Chapter 704B in 2001. Then, the western energy markets were in a state of crisis, Sierra neither owned nor controlled sufficient generation capacity to serve customers without relying heavily on volatile wholesale markets, electricity consumption was growing rapidly and the Company was not financially sound. Today, western energy markets are less volatile, the Company owns or controls sufficient generation to meet customer needs, sales growth has tapered and the Company is financially sound. The integrated resource planning ("IRP") process, completed by the Company under the supervision of the Commission, has worked. Between 2001 and 2015, Sierra invested in generation assets, improved its credit ratings and made long-term commitments to implement Nevada's energy policies. The Company has exceeded the State's renewable energy policy goals; at the same time, it provides service at reasonable rates, delivering the price and value package that Nevadans deserve. In 2018, the average price of electricity for Nevada residential customers was 11.86 cents per kilowatt-hour ("kWh"), which was less than the Mountain census division average and 1.03 or 8 percent below the national average. Commercial and industrial customers saw kWh prices 26.3 and 12.2 percent lower than the national average, respectively.

Yet, one implication of the IRP process is that decisions made years ago have long-term consequences. As the Commission recognized in the *Switch 704B Proceeding*[1] and the *Sands/Wynn/MGM 704B Proceedings*,[22] decisions approved by the Commission have cost consequences that extend decades. The transition of the Applicant to distribution only service ("DOS") will not reduce those costs; instead, the transition will increase prices to remaining customers unless an impact fee well in excess of the one proposed by Staff is assessed.

In light of the prevailing conditions, the Legislature reasonably assumed that the 704B process advanced the public interest in 2001. It allowed Nevada's largest energy consumers to use their own resources and credit to develop new generating resources for Nevada. The Legislature logically concluded that the successful development of new generation resources would reduce the cost of electricity for all Nevadans. Today, in contrast, the 704B process does not advance the public interest. As shown below, 704B activity has impacted the scale of Sierra's operations. The transactions proposed by customers do not reduce the total cost of electric consumption. Instead, applying the "substantially disproportionate" allocation of load growth to 704B applicants adopted by the Commission in the *Sands/Wynn/MGM 704B Proceedings* to Sierra would increase electric prices for Sierra's customers, which runs counter to the original purpose of Chapter 704B.

Since 2014, no 704B applicant has affirmatively shown that the transactions they have proposed will decrease the total cost of electricity for customers in Nevada Power's service territory. In fact, the evidence leads to the contrary conclusion. When a customer accesses wholesale markets at market prices at the same price that Sierra can access those markets, the price of electricity consumed in the state by sierra's customers is not reduced.

In summary, all signs point in one direction: a comprehensive review and reform of the 704B process is needed. Until such a review is completed and reforms are made, the Commission should insist upon a compelling showing by the applicant that the proposed

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1 See Order, Application of Switch Ltd. PUCN Docket No. 14-11007 (iss. June 11, 2015).

2 See Order, Application of Las Vegas Sands Corp., PUCN Docket No.15-05002 (iss. Dec. 3, 2015), Order, Application of Wynn Las Vegas, LLC, PUCN Docket No. 15-05006 (iss. Dec. 3, 2015), and Order, Application of MGM Resorts International, PUCN Docket No. 15-05017 (iss. Dec. 3, 2015).

transaction is in the public interest or use a much longer period for analyzing the impact of 704B transactions on base tariff general rates to protect the interest of remaining customers. At the same time, the Commission should shorten the base tariff energy rate analysis. Finally, the Commission should reinstitute non-bypassable charges for a period of at least six years. Any other approach would not be in the public interest.

Thus, the Company's recommended alternative analysis uses:

- A base tariff general rate analysis period of at least 14 years;
- A marginal generation demand cost allocation of regulatory assets as proposed by Staff;
- A base tariff energy rate analysis period of three years;
- Non-bypassable renewable base tariff energy rate ("R-BTER") and temporary renewable energy development ("TRED") charges for at least six years; and,
- Other charges (*e.g.*, governmental fees and demand-side management charges) as proposed by Staff.

The calculation of the impact fee alternatives are shown in Attachment 1, are supported below and will be further supported in the Company's direct testimony.

<u>Modelling Assumptions</u>

The Company's alternative analysis starts with Staff's Final Analysis and makes modifications.

Impact Fee. Staff's traditional directive requires the Company to remove all "placeholders" from the supply portfolio when conducting production cost modeling. This directive results in a supply plan that unrealistically relies more heavily on wholesale markets for the purchase of energy and capacity than Sierra's approved energy supply plan and integrated resource planning philosophy. As a result, the Company's alternative analysis is based upon a production cost modeling that maintains the placeholders in the supply portfolio. Because the expansion plan is more consistent with resource planning principles, Sierra's alternative analysis does not include a floor on base tariff energy rate credits.

Renewable Base Tariff Energy Rate ("R-BTER").

The R-BTER is the portion of the BTER that represents the costs for "out of the money" renewable energy power purchase agreements that the Company entered into to ensure compliance with Nevada's Renewable Portfolio Standard. Staff's traditional directives and final impact fee analysis for NRS Chapter 704B customers located in Sierra's service territory does not include any of these costs claiming there are none that are "out of the money". The Company enters into long-term power purchase agreements pursuant to federal and state public policy directives based on long-term load forecasts. These must-take stranded obligations represent non-variable costs; stated differently, the costs to the Company and its customers associated with these contracts are not reduced with a reduction in sales. Thus, the transaction proposed by GSR will reduce the Company's sales but will not result in a reduction of "R-BTER" costs that will be borne by remaining customers. If the Commission concludes that the transaction will not be contrary to the public interest, then it should require GSR to pay a non-bypassable R-BTER charge for six years for each of the R-BTER contracts commencing at the end of the impact fee period or, if the Commission uses the "non- bypassable" charge methodology, to pay a the R-BTER charge for six years of the life of the underlying contracts. The Company will provide further documentation of our position on the "out of the money" contracts in Direct testimony.

Off System Sales Credit. The Company is not including a credit in the impact fee for the assumed off-system sales of energy or capacity due to GSR's application. The Company recognizes that an off-system sales credit has been provided in some prior NRS chapter 704B impact analyses, however, due to the speculative nature of off-system sales actually occurring, the Company does not believe a credit is appropriate.

II. Justification for Duration of Analysis Periods

As the Commission has noted, "administrative agencies are not bound by *stare decisis*."[3] Indeed, if the Commission were to blindly apply the same analysis in this case that it did in a previous case, it "would result in ad hoc rulemaking in violation of NRS Chapter 233B" given that the specific time period or means of analyzing the impact of the transaction proposed by the Applicant "is not required by any statute or regulation creating a rule of general applicability."[4]

A. Resource Planning Process

The types of projects that the Company pursues to deliver reasonably priced, reliable electricity require long planning horizons. In a state where a large percentage of land is owned by the federal government, transmission and generation projects often trigger environmental reviews and take several years to plan, permit and construct. Moreover, these types of projects have long lives; transmission and generation projects have the potential to serve customers for decades.

To ensure that Nevada's energy policy objectives are met, the Commission supervises the Company's planning activities. The Company files an IRP at least once every three years. These filings seek approval of a 20-year plan and a three-year action plan, which identifies actions and expenditures necessary to implement the 20-year plan. Sierra must amend that plan when it:

1. Intends to submit an application for a permit to construct a utility facility, which was not previously approved as part of its three-year action plan,

2. Makes a commitment for the acquisition or construction of a facility that was not approved as part of the action plan,

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[3] Order, Application of Switch Ltd. at ¶111 [citations omitted].
[4] Id. at ¶ 112.

3. Makes a commitment for a long-term purchased power obligation which was not previously approved as part of the action plan, or

4. Makes a commitment for an option that was not available at the time the action plan was approved.

The regulatory process has been and is functioning well in Nevada. The Company, subject to the Commission's supervision and oversight, has implemented the State's energy policy objectives. At the same time, electricity prices have remained reasonable. These achievements as well as reliable service are a product of the IRP process.

The Commission reviews IRP filings and amendments, conducts a public hearing and accepts, rejects or modifies the plan. When the Commission accepts a plan, the reasonably incurred costs of effecting that plan are deemed prudent. Such costs affect the prices that Sierra charges customers for decades, not just a three-year, six-year or 10-year periods previously analyzed in 704B proceedings.

Long-term planning is essential for several reasons. First, it ensures electricity prices are reasonable in the long-term. Second, it ensures reliable service in the long-term. Third, it ensures that the State's economy can, in the long-term, thrive. In planning for the future, Sierra Power uses statistically adjusted end-use models to create three forecasts for three categories (not classes) of customers: residential, small commercial and industrial and large commercial and industrial. The first two models rely on projected customer counts and projected end-use consumption to develop category-wide consumption projections. The third model creates a category-wide forecast without relying on per-customer consumption. All three models are driven by, among other things, economic variables. In addition, the large commercial and industrial model excluding mines and other large customers, which are individually forecasted based on the Company's Major Account, Economic Development, Energy Delivery personnel and customer input related to changes in usage and maximum demand over the next several years. The large commercial and industrial therefore is a combination of modeling and customer specific forecasts.

Based upon these load forecasts produced by these models and customer specific information, vetted in IRP filings and accepted by the Commission, Sierra has invested hundreds of millions of dollars into long-term commitments since 2001 to further Nevada's energy policy goals of delivering clean, reliable energy at a reasonable price. The following table identifies long-term commitments, including anticipated remaining costs and Commission approved costs, made to meet the existing and forecasted needs of Nevada Power's customers.

Contract Name	Docket No. Approved	Anticipated Remaining Cost
Renewable Energy		
PPAs (Commercial)		
Beowawe	05-5010	$ 49,178,776
Boulder Solar II	15-11029	$ 137,967,281
Brady	Qualifying Facility - Legacy ("QF-Legacy")[1]	$ 13,256,630
Burdette	04-08004	$ 71,733,244
Galena 3	06-05040	$ 97,811,754
Homestretch	QF-Legacy	$ 496,400
Hooper	QF-Legacy	$ 691,343
Kingston	N/A	$ 184,985
Mill Creek	N/A	$ 7,087
Nevada Solar One (SPPC)	02-12039	$ 70,527,880
RO Ranch	N/A	$ -
Soda Lake II	QF-Legacy	$ 10,800,606
Steamboat 2	QF-Legacy	$ 21,090,950
Steamboat 3	QF-Legacy	$ 21,182,092
Switch Station 2 (SPPC)	15-11029	$ 209,243,622
TCID New Lahontan	QF-Legacy	$ 17,682,563
TMWA Fleish	07-01036	$ 11,275,099
TMWA Verdi	07-01036	$ 13,945,673
TMWA Washoe	07-01036	$ 10,203,242
USG San Emidio	11-08010	$ 146,463,965
Leased Units		
Fort Churchill Solar		$ 69,000,000
PPAs (Pre-Commercial)[3]		
Techren II	17-02008	$ 559,131,689
Techren IV	17-11003	$ 60,576,511
Turquoise	17-11003	$ 109,104,579
Battle Mountain Solar	18-06003	$ 250,639,470
Dodge Flat Solar	18-06003	$ 476,934,332
Fish Springs Ranch Solar	18-06003	$ 250,998,545
Copper Mountain Solar 5	18-06003	$ 496,224,057
Eagle Shadow Mountain Solar	18-06003	$ 528,968,267
Techren V	18-06003	$ 101,254,512
Liberty (CalPeco) EBSA	09-12002 & 10-07003	$ 11,581,818
Generating Units		**Approved Cost**
Tracy CC	05-08004	$450 million
Other Assets		
One Nevada Transmission Line		$509.6 million.

The consequences of the sound decisions made through the IRP process extend for decades. The Commission recognized these consequences in both the *Switch 704B Proceeding* and the *Sands/Wynn/MGM 704B Proceedings*. The order in the *Switch 704B Proceeding* acknowledges that Nevada Power made significant progress towards "diminishing its reliance on the wholesale energy market,"[5] which was one of the State's energy policy objectives.[6] The order also acknowledged that Nevada Power entered into a number of high-priced, long-term renewable energy contracts for the purpose of advancing Nevada's renewable energy goals.[7] Likewise, the order recognized that Nevada Power had already started to implement a "legislatively sponsored initiative to reduce the State's reliance on coal" which provided "a social and environmental benefit" at "an economic cost."[8] All of these prudent decisions result in costs that extend well beyond a three-year, six-year and even a 10-year impact period.[9] Not surprisingly, just six months later in the *Sands/Wynn/MGM 704B Proceedings*, the Commission found that all of these "significant investments remain on Nevada Power's system."[10] The same decisions are made through the IRP process for Sierra as well.

However, the circumstances since the Commission's orders in the *Sands/Wynn/MGM 704B Proceedings* have continued to evolve. Since the Commission issued orders in the *Sands/Wynn/MGM 704B Proceedings*, the foundational assumptions that supported the Commission's order have crumbled. As shown below, the base tariff general rate components of

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5 Order, *Switch 704B Proceeding* at ¶ 95. In Nevada Power's 2003 IRP, the Company showed that it need 5,460 megawatts of capacity to meet is service obligations, but that it owned only 2,405 MW of generating capacity. Id. It owned just 44 percent of the capacity it needed to adequately meet the needs of customers. In the Company's 2014 IRP, it demonstrated that it owned approximately 72 percent of the capacity it needed to meet customer needs and had long-term contracts in place to meet additional demand.

6 On February 22, 2001, Governor Kenny Guinn announced the Nevada Energy Protection plan. The plan called for energy conservation programs, a plan to accelerate the construction of new power plants and the addition of new transmission lines to stabilize energy prices.

7 Order, *Switch 704B Proceeding* at 96.

8 Order, *Switch 704B Proceeding* at 97.

9 See Order, *Switch 704B Proceeding* at 101.

10 Order, Application of MGM Resorts International at ¶ 153.

impact fees imposed in 704B proceedings will be insufficient to mitigate price increases to be borne by remaining customers in Sierra's future rate cases, it will take at least two decades for Sierra's retail electric sales to return to the 2018 IRP baseline and the exclusion of the R-BTER and TRED non-bypassable charges must be reconsidered. Recognizing these developments compel a different outcome in this proceeding.

B. The base tariff general rate analysis period should be at least 14 years.

The base tariff general rate component of impact fees collected by Sierra in past proceedings will be insufficient to hold Sierra's remaining customers harmless in Sierra's next general rate review proceeding. Specifically, the Company reviewed how the base tariff general rate component of impact fees already received by the Company impacts full service margin revenue and remaining customers. The results of that analysis are shown in the following table.

Margin Impact of Becoming Distribution Only Service Customers
($, millions)

	2019	2020	2021	2022	2023	2024	2025	2026	2027
Sierra Pacific									
Loss of full service revenue (A)	$ (4.0)	$ (4.0)	$ (4.0)	$ (4.0)	$ (4.0)	$ (4.0)	$ (4.0)	$ (4.0)	$ (4.0)
Replaced by:									
Impact fee	1.4	0.6	0.6	0.6	-	-	-	-	-
Distribution only	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Transmission	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
	3.8	3.0	3.0	3.0	2.4	2.4	2.4	2.4	2.4
Impact spread to other customers	-	1.0	1.0	1.0	1.6	1.6	1.6	1.6	1.6
Margin difference	**$ (0.2)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

The bottom line is that the transition of customers to DOS service reduces full service margin revenue by $4 million. While DOS service revenue and transmission service revenue will increase, the impact fee amortization is insufficient to hold Sierra's remaining customers harmless. All other things being equal, Sierra's remaining customers will pay base tariff general rates that are $1 million dollars higher than they otherwise would be in the next general rate review proceeding and potentially $1.6 million higher than they otherwise would be in the subsequent general rate review proceeding. As the orders in the *Sands/Wynn/MGM 704B Proceedings* make clear, the Commission was relying on load growth to mitigate this impact. Unfortunately, load growth will not mitigate this impact.

Load growth is one of the significant factual circumstances that the Commission must consider when it evaluates the impact of a transaction proposed by an applicant under Chapter 704B. A related factor is the level of 704B activity, as well as the potential for future 704B activity. The interplay between the two – potential load growth on the one hand and the potential of load reductions,[11] on the other hand, are key to understanding how the transaction proposed by the Applicant will impact other customers. This approach – focusing on the interplay between 704B activity and load growth to assess the validity of any impact fee recommendation – is perfectly consistent with the Commission's orders in the *Switch 704B Proceeding* and the *MGM/Wynn 704B Proceedings*.

In Docket No. 14-11007 (the *Switch 704B Proceeding*), the Commission denied a 704B application, finding "that a 3-year analysis of the costs associated with [the applicant's transition to DOS service] is insufficient to protect ratepayers from the quantifiable costs that extend beyond a 3-year period."[12] The order continues, "[s]pecifically, the Commission finds that the use of a 3-year Impact Analysis that relies so heavily on forecasted load growth to mitigate the potential damage to ratepayers following [the applicant's] proposed [transition to DOS service] neglects to consider the evidence in this Docket that clearly shows the existence of costs that will not be covered under any of the proposed impact analyses offered in this Docket."[13]

The order in Docket No. 14-11007 acknowledged "that while Nevada Power's load

[11] It is important to recognize that 704B activity differs in a significant way from energy efficiency or demand side management programs. Energy efficiency programs reduce energy consumption within the Company's service territory, effectively reducing the loading on the Company's generation units, transmission system and its distribution system. 704B activity somewhat reduces the load that the Company has to serve; it does not, however, result in any reduction on the loading of the Company's transmission and distribution systems. In fact, no post 2013 704B applicant has proposed in their application to construct or contract with new generating or transmission resources located within Nevada Power's balancing authority. This actually detrimentally impacts transmission import capacity.

[12] Order, *Switch 704B Proceeding* at 101.

[13] Id.

forecast estimates general load growth in its system," the Company raised real "concerns regarding the reduction in sales associated with its large customer class" and that these concerns "must be considered in assessing whether load growth will actually keep the costs of Nevada Power's remaining customers static following [the applicant's transition to DOS service]."[1414] The Commission found that, based on "Nevada Power's concerns regarding the lack of growth to its Large C&I customer classes" Nevada Power's "remaining customers" could be "adversely affected" if the applicant were not required to pay an impact fee commensurate with the costs the application would "pay should it remain a bundled retail customer."[15]

Ultimately, the Commission recognized that the transaction proposed by the applicant in Docket No. 14-11007 would result in increased costs to Nevada Power's remaining customers.[1616] "Accordingly, the Commission finds that given the way rates are designed in Nevada to collect the electric utility's annual revenue requirement via class-specific rates and revenue requirements, Nevada Power's current Large C&I customers are more likely than not to see increased costs as a result of [the applicant's transition to DOS service] because Nevada Power's Large C&I customer load forecast does not show enough growth to account for the loss in sales resulting from [the applicant's] departing load."[17] The Commission also acknowledged that "any portion of the requirement not retained by the Large C&I customer classes would be reallocated to other customer classes, including the small commercial and residential classes, resulting in increased costs to those remaining customers."[18]

The Commission further found, "the use of an analytical framework developed over a decade ago, and most recently used in southern Nevada in 2003" was "insufficient at this time for the purposes of assessing the impact" of the transaction proposed by the applicant on remaining

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[14] Id. at 103
[15] Id.
[16] Id. at ¶ 104.

customers.[19] The Commission concluded "Accordingly, given that the load forecast does not show the necessary growth to Nevada Power's Large C&I customer classes to replace [the applicant's] load sales, and given that there are quantifiable costs that extend well beyond the three years, the Commission finds that, based on the evidence in this Docket, remaining customers will experience an increase in costs as a result of the [applicant's transition to DOS service,] even if [the applicant pays the impact] fee as calculated by Staff."[20]

In the *Sands/Wynn/MGM 704B Proceedings*, the Commission approved three transactions proposed by 704B applicants in the *Sands/Wynn/MGM 704B Proceedings*. The Commission assessed a base tariff general rate impact fee using a six-year period, assessed a net base tariff energy rate impact fee using a six-year period and required the applicants to pay non-bypassable charges to address several categories of costs. With respect to the base tariff general rate component of the impact fee, the Commission also addressed specific cost categories. Those costs were: the emissions reduction and capacity replacement plan approved generation assets and the applicant's load ratio share of costs associated with the acquisition of a 25-percent interest in the Silverhawk. Non-bypassable charges were assessed to address: long-term renewable energy contracts (the "R-BTER"), the Merrill Lynch regulatory asset, the renewable energy program rate, the temporary renewable energy development charge and emissions reduction and capacity replacement plan and non- emissions reduction and capacity replacement plan regulatory assets.

In regards to the non-bypassable charges, the Commission found that the "[non-bypassable charge, or NBC, methodology] adequately account[ed] for the aggregate impact of the 2015 NRS 704B Applicants' total load proposing to depart bundled retail service."[21] The order recognizes the need to analyze the holistic impact of 704B transactions on remaining customers; the Commission eschewed a myopic focus on each transaction, opting instead to look at the broader picture because the overarching goal is to ensure that transactions proposed by customers pursuant to Chapter 704B are not contrary to the public interest. "[T]he Commission finds that NRS

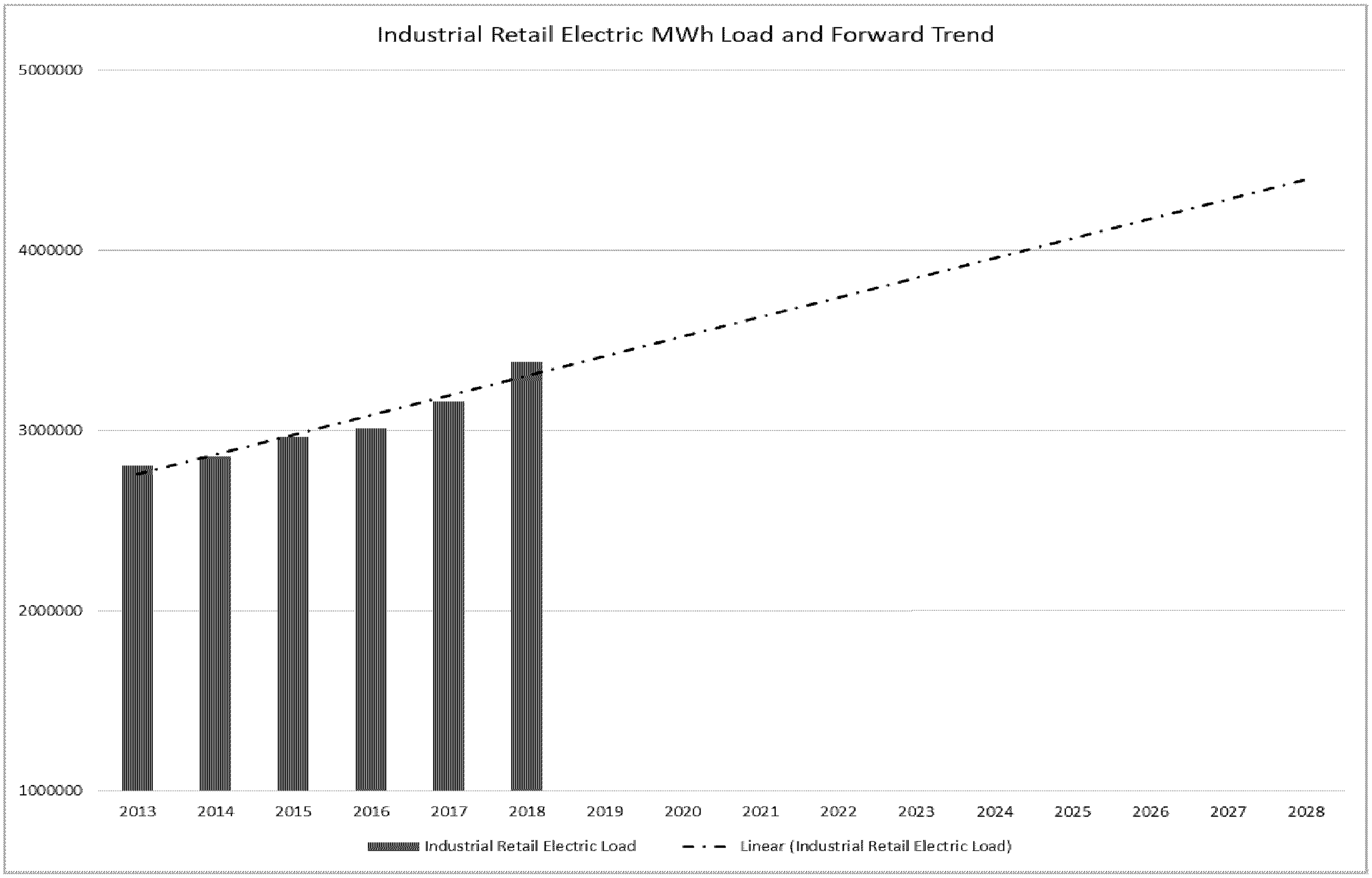
[21] Order, Application of MGM Resorts International at 150.

704B.310 does not prohibit the Commission from assessing whether approval of a single proposed transaction, in relation to other, similar pending applications requiring the same review will be contrary to the public interest."[22] The Commission continued, "In fact, in considering whether approval of the proposed transaction will be contrary to the public interest, the Commission's consideration is 'without limitation.'"[23] Thus, the Commission concluded that it must consider the aggregate impact of the proposed transactions in order to protect the public interest.

Based upon these conclusions, there were at least two foundational assumptions the Commission grounded the non-bypassable charge methodology: 1) that Nevada Power's retail electric sales would return to the 2015 baseline by 2025 and 2) that the R-BTER and TRED non-bypassable charges would continue for the life of the associated contracts, providing a counterweight to the substantially discriminatory allocation of load growth to 704B applicants. These foundational assumptions have crumbled. There no longer is any justification for what the Commission acknowledged as a substantially disproportionate allocation of load growth in favor of 704B applicants to the detriment of Nevada Power's remaining customers.

1. Actual sales to the large commercial and industrial are declining.

The following table shows actual, weather normalized sales to customers in the large industrial class between 2013 and 2018.



22 Id. at ¶ 150.

23 Id.

2. Retail electric sales will not return to the 2018 baseline for at least two decades

With respect to load growth, the orders in the *Sands/Wynn/MGM 704B Proceedings* anticipated that it would take a decade for system load growth to equal the sales reduction associated with the transactions proposed by the applicants. The Commission used a six-year period to determine the base tariff general revenue requirement, however, with the understanding that "departing customers are allocated approximately 100 percent of the benefits associated with load growth."[24] The Commission found that this "disproportionate allocation of the benefits associated with load growth is ***only*** acceptable because the BTGR costs are 'net' of Regulatory Assets/SB 123 Costs, ***and*** because the time period selected for the BTGR will be balanced with the time periods for the other cost components of the impact fee (i.e., the Net-BTER & the non-bypassable charges.)"[25]

In addition, the orders in the *Switch 704B Proceeding* and the *Sands/Wynn/MGM 704B Proceedings* establish the following principles:

1. The Commission's analysis must account for past, present and future 704B activity in order to protect the public interest;

2. Potential load growth should be weighed in determining the base tariff general rate impact fee analysis period;

3. The simplifying assumption used by Staff in its directive – the removal of placeholders – places significant and unquantified risk on remaining customers that is acceptable only if balanced by other components of the impact fee; and,

4. Different categories of impacts (e.g., base tariff general and base tariff energy impacts) can be analyzed using different time periods in order to protect remaining

[25] Id. at ¶ 165.

customers and reach a conclusion that ensures the transaction proposed by an applicant is not contrary to the public interest.

Staff's impact analysis does not take these important principles into consideration.

The basis for the "non-bypassable charge" methodology – a six-year base tariff general rate impact analysis and a six-year net-base tariff energy rate impact analysis coupled with a credit for off-system sales, no longer exist. It will take Sierra (the evidence provided below) much longer than 10 years to "replace" all of the retail electric sales previously made to large commercial

[26] Id. at ¶ 165.