BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Application of Georgia-Pacific Gypsum LLC to purchase energy, capacity, and/or ancillary services from a provider of new electric resources.	))))	Docket No. 18-09015

At a general session of the Public Utilities Commission of Nevada, held at its offices on February 15, 2019.

PRESENT: Chairman Ann Wilkinson
Commissioner Ann Pongracz
Commissioner C.J. Manthe
Assistant Commission Secretary Trisha Osborne

ORDER

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

I. INTRODUCTION

On September 25, 2018, as amended on October 9, 2018, Georgia-Pacific Gypsum LLC ("Georgia-Pacific") filed an Application to purchase energy, capacity, and/or ancillary services from a provider of new electric resources.

II. SUMMARY

The Commission grants the Application, subject to the payment of an impact fee and the satisfaction of the compliances and directives delineated in this Order.

III. PROCEDURAL HISTORY

• On September 25, 2018, Georgia-Pacific filed an Application with the Commission, designated as Docket No. 18-09015, to purchase energy, capacity, and/or ancillary services from a provider of new electric resources.

• Georgia-Pacific filed the Application in accordance with Chapters 703 and 704 of the Nevada Revised Statutes ("NRS") and the Nevada Administrative Code ("NAC"), including but not limited to NAC 704B.340 and 704B.380.

• The Regulatory Operations Staff ("Staff") of the Commission participates as a matter of right pursuant to NRS 703.301.

• On October 2, 2018, the Attorney General's Bureau of Consumer Protection ("BCP") filed a Notice of Intent to Intervene pursuant to Chapter 228 of the NRS.

• On October 9, 2018, Georgia-Pacific filed an Amended Application.

• On October 10, 2018, the Commission issued a Notice of Application.

• On October 10, 2018, the Commission issued a Notice of Prehearing Conference.

• On October 19, 2018, Tenaska Power Services Co. ("Tenaska") filed a Petition for Leave to Intervene ("PLTI").

• On October 30, 2018, Nevada Power Company d/b/a NV Energy ("NPC") filed a letter notifying the Commission that it would become a party in this matter pursuant to NAC 704B.310 and 703.595.

• On November 1, 2018, the Hearing Officer held a prehearing conference in accordance with NAC 703.655. Georgia-Pacific, Tenaska, NPC, BCP, and Staff agreed upon a procedural schedule.

• On November 5, 2018, the Hearing Officer issued a Procedural Order adopting a procedural schedule.

• On November 5, 2018, the Commission issued a Notice of Hearing.

• On November 5, 2018, the Hearing Officer issued an Order granting the intervention of Tenaska.

• On November 14, 2018, the Hearing Officer issued Procedural Order No. 2 amending the procedures adopted in the November 5, 2018, Procedural Order.

• On January 24, 2019, the Hearing Officer held a hearing. Georgia-Pacific, NPC, BCP, and Staff made appearances. Pursuant to NAC 703.730, the Presiding Officer accepted Exhibits 1-13 and Confidential Exhibits C-1 to C-4 into the record as evidence.

IV. APPLICATION

Party Positions

Georgia-Pacific

1. Georgia-Pacific states that it notified Staff, NPC, and BCP of its intent to purchase energy, capacity, and ancillary services from a provider of new electric resources by

issuing its letter of intent on March 26, 2018. Georgia-Pacific subsequently met with Staff, NPC, and BCP to discuss its intent on April 19, 2018. (Ex. 1 at 3, Mullins-Direct-2; Ex. 2 at 2.)

2. Georgia-Pacific states that it is an "eligible customer" under NRS Chapter 704B. It is a nongovernmental commercial or industrial end-use customer that has an average annual load of one megawatt or more in the service territory of NPC. Specifically, Georgia-Pacific's industrial plant in Apex is an end-use customer of NPC with an average electric consumption of approximately 2.5 megawatts ("MW"). (Ex. 1 at 3-4, Mullins-Direct-3; Ex. 2 at 2, 6.)

3. Further, Georgia-Pacific states that it is also an eligible customer pursuant to NV Energy's Open Access Transmission Tariff ("OATT"), which defines an eligible customer for transmission service to include any eligible retail customer taking unbundled transmission service pursuant to a retail open access program. (Ex. 1 at 4.)

4. Georgia-Pacific recites that it has selected Tenaska as its Provider. Georgia-Pacific continues to negotiate with Tenaska and expects that a definitive agreement will be reached, which will ensure that the full requirements of Georgia-Pacific's facility are met, that Tenaska will service as Georgia-Pacific's scheduling coordinator, and will include compliance with the Nevada Renewable Portfolio Standard ("RPS"). (Ex. 1 at 5, Mullins-Direct-4; Ex. 2 at 7, 10.)

5. Georgia-Pacific will purchase energy, capacity, and ancillary services from new electric resources as defined by NRS 704B.110. All electric resources will come from generation assets not owned by NV Energy or under contractual commitment to NV Energy. Georgia-Pacific and its Provider plan to adhere to a compliance policy consistent with the stipulation in the Caesars NRS 704B application (Docket No. 16-11034). (Ex. 1 at 6; Ex. 2 at 7-8.)

6. Georgia-Pacific will utilize Network Integration Transmission Service pursuant to NPC's OATT. Georgia-Pacific will also execute a Network Operating Agreement ("NOA") with NPC. Upon execution, Georgia-Pacific will file the NOA with the Commission pursuant to NAC 704B.370(1)(b). Georgia-Pacific will also enter into a distribution-only service ("DOS") agreement pursuant to NPC's DOS Rider. (Ex. 1 at 6-7; Ex. 2 at 7-8.)

7. Georgia-Pacific commits to pay its share of fees and assessments, including certain other non-bypassable taxes and assessments, required under NRS 704B. Georgia-Pacific will also comply with the RPS. Georgia-Pacific also commits to comply with the requirement to offer a "10-percent contract" to NPC pursuant to NRS 704B.320. (Ex. 1 at 7-8; Ex. 2 at 5, 10.)

8. Georgia-Pacific agrees with Staff's impact fee analysis as a starting point. However, Georgia-Pacific proposes that Staff's non-inclusion of an off-system sales credit should be reversed. Previous NRS 704B applicants have received an off-system sales credit and Georgia-Pacific should be fairly credited with off-system sales, which would reduce Georgia-Pacific's impact fee by $34,000. (Ex. 1 at 10-11, Mullins-Direct-5)

BCP

9. BCP states that it agrees with Staff's impact fee analysis because it uses the same methodology used to analyze other NRS 704B applications (with one exception), it treats Georgia-Pacific and other NRS 704B applicants fairly and equitably, and it ensures that remaining ratepayers are not burdened by Georgia-Pacific's departure. (Ex. 6 at 2.)

10. BCP agrees with Staff's position in this case to not credit Georgia-Pacific with projected off-system sales. In the MGM exit case (Docket No. 15-05017), the Commission found that the PROMOD calculation of off-system sales provided a reasonable proxy for off-system and Energy Imbalance Market ("EIM") sales. The Commission did not find that the

PROMOD calculation of off-system sales was accurate. BCP states that NV Energy now has data showing that off-system sales and EIM sales have not occurred as a result of NRS 704B departures. BCP acknowledges, however, that while NPC has pertinent data, it appears that the data has not been examined to specifically identify whether off-system sales related to NRS 704B exits have occurred or not. BCP explains that NV Energy does not appear to have a significant or consistent market advantage to sell power over other utilities in the region, as NV Energy's marginal plants are similar to others in the region, as are NV Energy's natural gas fuel costs. Even though NV Energy may have surplus power to sell, more sales are not likely to be transacted. Accordingly, Georgia-Pacific's proposal to include a credit for off-system sales should be rejected. (Ex. 6 at 3-6, 8-9; Tr. at 37, 39, 41.)

11. BCP agrees with Staff's two placeholders for the following: 1) Reid Gardner/Navajo book costs and decommissioning and remediation costs, and 2) excess ADIT. Both issues are unresolved at this point and will be determined in future cases. (Ex. 6 at 8.)

12. BCP recommends that the Commission not adopt NPC's alternative impact analysis. BCP is unclear as to what NPC's alternative recommendation is but interprets such to include: 1) the inclusion of placeholders to better match NPC's integrated resource plan and 2) to extend the time frame over which the Renewable Base Tariff Energy Rate (" R-BTER") costs are collected from six years to the life of the underlying contracts. BCP states that NPC did not provide a reason why Staff should deviate from its past methodology, which has been repeatedly approved by the Commission. BCP opines that using planned, but not approved, placeholders would create a more burdensome and contentious impact fee process. Regarding NPC's R-BTER proposal, BCP acknowledges NPC's concern, but points out that the Commission has previously addressed this issue by limiting the charge to the impact period, which the

Commission reasoned balances the need for certainty for NRS 704B applicants with the need to recover the costs. Extending the recovery of the R-BTER beyond six years creates administrative burdens with true-ups occurring for several decades. (Ex. 6 at 9-11, JEM-4).

NPC

13. NPC explains that in examining NRS 704B applications, the Commission is tasked with protecting the electric utilities in this state and their remaining customers. Remaining customers must not be subject to increased costs as a result of an NRS 704B transaction and the transaction must not be otherwise contrary to the public interest. NRS 704B applicants bear the responsibility to demonstrate that the proposed transaction is not contrary to the public interest. NPC states that the bar should be high. (Ex. 4 at 3.)

14. NPC explains that NRS Chapter 704B was established when the energy market for Nevada and the western United States was quite different (including supply shortages and high prices for electricity). Currently, NV Energy is not dependent on regional energy markets, the energy markets in the western United States are not viewed as "dysfunctional," and eligible customers are not proposing to develop new generation resources within the Nevada Balancing area authority. (Ex. 4 at 5-7.)

15. NPC argues that Georgia-Pacific's Application is legally deficient. Georgia-Pacific has not included the required 10-percent contract information in its Application as required by NRS 704B.320. Georgia-Pacific acknowledges that it does not include the required information as it was still negotiating a contract with Tenaska. The Commission can either require Georgia-Pacific to amend its application to include the required information and restart the 150-day timeframe for review, or it may deny the application and allow Georgia-Pacific to re-file a complete application. (Ex. 4 at 7-9.)

16. NPC also contends that the Application does not provide sufficient information to meet Georgia-Pacific's burden that the proposed transaction in not contrary to the public interest as required by NRS 704B.310(6). The Application does not provide any evidence or information as to how the proposed transaction will not increase costs for the electric utility or remaining customers. NPC argues that granting NRS 704B applications inherently puts upward pressure on electric prices. NPC has made investments in long-lived assets and long-term obligations to service its customers, which the Commission approved. Costs associated with those investments will be spread over fewer billing determinants resulting in electric prices that are higher than they need to be and were expected to be. The Commission has attempted to address this issue by assessing impact fees to NRS 704B applicants. However, the Application is silent as to whether Georgia-Pacific will pay an impact fee or if the impact fee is sufficient to ensure that NPC's and remaining customers' costs are not increased. (Ex. 4 at 9-10.)

17. Granting the Application could also increase NPC's costs. In NPC's 2017 general rate case, the Commission directed NPC to begin calculating carrying charges on the unamortized Base Tariff General Rate ("BTGR") portion of impact fees paid to NPC. NPC is now experiencing increased interest expense as a result, which is inconsistent with NRS Chapter 704B. (Ex. 4 at 10-11; Tr. at 28-29.)

18. NPC states that the Application does not provide any evidence that the proposed transaction will not impair system reliability or the ability to provide electric service to remaining customers. (Ex. 4 at 11.)

19. NPC recommends that the Commission require Georgia-Pacific to amend its application to address the identified "public interest" legal deficiencies. (Ex. 4 at 11-12.)

20. NPC goes on to state that the proposed transaction does not advance the goals of NRS Chapter 704B as it does not add energy, capacity, and ancillary services to the supply in the State. Georgia-Pacific proposes to purchase energy from Tenaska as opposed to building or contracting with a new generation resource in Nevada or investing in transmission assets to provide access to a different regional market. (Ex. 4 at 12.)

21. NPC argues that market transactions as proposed by Georgia-Pacific do not add energy to the supply in this State as contemplated by NRS Chapter 704B. When an eligible customer proposes to purchase and import financially firm energy from a regional market to which NV Energy already has access, the transaction does not add energy or capacity to the supply of energy and capacity in Nevada. The same level of generation and transmission system capacity that existed prior to the NRS 704B application remains. When an eligible customer proposes to buy energy at indexed prices in a market where NV Energy has credit and operations ability to procure energy in the same market without a substantial cost adder, the transaction does not add energy or capacity to the supply in Nevada. NRS Chapter 704B had a resource planning objective to improve resource adequacy. The transaction proposed by Georgia-Pacific results in a deterioration of resource adequacy by shifting the resource balance through reduced resource optimization opportunities between internal generation and market purchases available to existing customers. Georgia-Pacific should either be required to amend its Application to address this issue, or the Commission should deny the Application and allow Georgia-Pacific to refile when it can provide information to meet its burden of proof. (Ex. 4 at 14-18.)

22. NPC also proposes an alternative analysis and proposed adjustments to Staff's Final Analysis. First, NPC proposes to remove the Base Tariff Energy Rate ("BTER") component of the impact fee "credits" associated with putative "efficiency" gains embedded in

Staff's Final Analysis. Staff's Final Analysis removes all "placeholders" from the supply portfolio when conducting production cost modeling. This results in a supply plan that relies more heavily on wholesale markets for the purchase of energy and capacity than NV Energy's approved energy supply plan and integrated resource planning philosophy. Removal of the credits results in a more accurate depiction of NV Energy's energy supply plan and integrated resource plans as approved by the Commission. (Ex. 4 at 18; Ex. 5.)

23. NPC also proposes a ten-year analysis period versus the six-year period used by Staff. A primary factor in determining the appropriate analysis period is an assumption that NPC will have steady load growth to offset the impact of Georgia-Pacific no longer being a fully-bundled customer. The steady load growth assumption, however, must be revisited given the Commission's decision in Docket No. 18-06009 (Fulcrum Biofuels NRS 704B Application) and the number of existing customers expressing interest in filing an NRS 704B application. In Docket No. 18-06009, the Commission found that new businesses to Nevada do not have to pay an impact fee or non-bypassable charges for their incremental load because NPC did not specifically plan for that entity in its load forecast. NPC proposes that the steady load growth assumption must be revisited. (Ex. 4 at 18-19; Ex. 5.)

24. Finally, NPC opines that Georgia-Pacific should be required to pay the R-BTER charges for the remainder of the life of the R-BTER contracts. NPC entered into the contracts, in part, to meet the demands created by Georgia-Pacific. The obligations do not go away because Georgia-Pacific chooses to use an alternative energy provider. The costs to NPC and its customers associated with the underlying contracts do not vary based on sales. The transaction proposed by Georgia-Pacific will reduce NPC's sales and will not result in a reduction of R-BTER costs. (Ex. 4 at 20-21; Ex. 5.)

Staff

25. Staff recommends that the Commission approve Georgia-Pacific's Application under the terms, conditions and payments contained in Staff's Final Impact Analysis and testimony filed in this matter. Staff's Final Impact Analysis utilizes a non-bypassable rate methodology to determine the impact of Georgia-Pacific's departure from bundled retail electric service over the six-year period beginning April 1, 2019, through March 21, 2025. Under Staff's methodology, a portion of Georgia-Pacific's impact fee represents Georgia-Pacific's energy load ratio share of NPC's costs associated with the Renewable Energy Program Rate ("REPR"), the Temporary Renewable Energy Development charge ("TRED"), the R-BTER, and the Merrill Lynch charge (collectively, the "non-bypassable charges"). (Ex. 8 at 3.)

26. In addition to the non-bypassable charges, Staff recommends that Georgia-Pacific be required to pay an upfront fee, which Staff has calculated to be $1.325 million on a net present value ("NPV") basis. The separate cost components of the upfront fee are as follows: 1) $1.120 million representing the BTGR cost component; 2) $0.175 million representing the net-BTER component; 3) ($0.142) million representing the variable operations and maintenance ("O&M") cost components; 4) $0.009 million representing obligations for non-Emissions Reduction and Capacity Replacement ("ERCR") regulatory assets; 5) $0.070 million representing the obligation for ERCR regulatory assets 6) $0.018 million representing the Energy Efficiency ("EE") cost component; 7) $0.012 million representing the demand side management ("DSM") recapture payment; and 8) $0.063 million representing local government fees. (Ex. 8 at 3 and Ex. 7 at 2-5.)

27. In addition to the upfront fee, Staff recommends that Georgia-Pacific should be subject to non-bypassable charges for a six-year period. These non-bypassable charges are

associated with the REPR, the TRED, the out-of-the-money costs associated with Nevada's renewable portfolio standard established by NRS 704.78921 (R-BTER), and the Merrill Lynch charge. Georgia-Pacific would also be responsible for its share of the Economic Development Electric Rate Rider Program ("EDRR") established pursuant to NRS 704.7875. The EDRR charge would be ongoing as all customers are required to pay this rate, including DOS and transmission-only customers. (Ex. 7 at 5; Ex. 8 at 3-4.)

28. Staff also recommends placeholder items for two issues that cannot be valued at this time, but Georgia-Pacific should be responsible for its share of the associated costs and/or benefits from those issues. The placeholder issues Staff has identified are as follows: 1) the costs and/or benefits associated with the Reid Gardner and Navajo remaining net book value and remaining decommissioning and remediation costs, and 2) excess accumulated deferred income tax ("ADIT") associated with the Tax Cut and Jobs Act. (Ex. 8 at 3-4, Ex. 7 at 6-7.)

29. Staff explains that the BTGR component represents the difference between the BTGR revenue Georgia-Pacific would pay as a fully-bundled customer versus the revenue Georgia-Pacific would pay as a DOS-only customer. The net-BTER cost component represents the estimated impact that will result to NPC's fuel and purchase power costs as a result of Georgia-Pacific's load being removed from the total load that NPC is required to serve excluding the renewable energy costs collected through the R-BTER. The variable operations and maintenance cost component represents the effect Georgia-Pacific's departure would have on NPC's generation units. Once Georgia-Pacific exits bundled service, NPC's generation units will incur lower variable operations and maintenance costs. The non-ERCR regulatory asset cost component represents Georgia-Pacific's marginal cost of service study percentage share of the Mohave decommissioning costs along with other existing and future regulatory assets and

liabilities. The obligation for ERCR regulatory assets cost component represents Georgia-Pacific's demand cost allocation share of generation assets that were approved while Georgia-Pacific was a customer, which includes costs associated with portions of Las Vegas Cogeneration, SunPeak (2014) 222 MW, Nellis (2015) 15 MW, and Silverhawk (2017) 54 MW. The EE cost component represents the costs associated with implementing and operating NPC's demand-side management ("DSM") programs that have been approved by the Commission as well as any financial disincentive due to the DSM programs for the EE rate effective period of October 2018 through September 2019. The DSM recapture cost component represents the repayment of prorated incentives based upon the remaining life of each program that were provided by NPC to Georgia-Pacific over the five years prior to Georgia-Pacific's departure from bundled service.[1] The local government fee cost represents the five percent Franchise Fee mandated by Clark County on energy revenue NPC receives in Clark County. (Ex. 8 at 7-10; Ex. 7 at 2-5.)

30. Staff explains that it did not credit Georgia-Pacific with any off-system sales. Staff explains that it has never supported a 100 percent off-system sales credit in the context of NRS 704B analyses, and due to the changing circumstances surrounding NRS 704B applications, Staff now believes that it is not reasonable or practical to assume that NV Energy can continue to make the level of off-system sales that the off-system sales credit assumes. As more customers depart under NRS 704B, NV Energy will need to make more off-system sales to cover the pre-paid credit granted to customers who have transitioned to DOS service. Further, NRS 704B.110 limits the capability of NV Energy to sell excess generation to a "provider of new electric resource." Also, as more providers serve exited customers, the available counter parties to

[1] Staff's DSM recapture and its calculation are explained in Ex. 9 at 9-12, AC-5, AC-6, and AC-7.

whom NV Energy can sell surplus energy and capacity dwindles. Staff, though, acknowledges that it has not specifically examined actual data to determine if off-system sales related to previous NRS 704B exits have materialized or not. Exclusion of the off-system sales credit results in an approximate $36,000 increase in Georgia-Pacific's impact fee. (Ex. 8 at 6-7, POL-3; Ex. 11 at 4; Tr at 55-59.)

31. Staff explains that it used a scaling factor of twenty during the analysis of Georgia-Pacific's impact. Staff requested that Georgia-Pacific's load be scaled in order to allow a better opportunity for NPC's PROMOD model to eliminate any potential miscalculations. Georgia-Pacific's load was then reduced by the same factor. (Ex. 8 at 7, POL-03; Ex. 11 at 4.)

32. Staff states that its analysis is not outcome driven. Staff uses the latest and most logical input assumptions available. In this case, Staff used the most recently Commission-approved inputs from NPC's third amendment to its 2016-2035 Integrated Resource Plan ("IRP") (Docket No. 17-11004). (Ex. 8 at 4-6.)

33. Regarding the impact fee analysis period, Staff supports a six-year period. First, when looking at wholesale capacity and energy prices, current market prices are at historic lows. Market prices are lower than NV Energy's embedded average system cost which leads to a longer impact fee period being needed to protect remaining customers. Next, per NV Energy's latest IRP, there is essentially no open position except for some planning reserve margin. As NV Energy has built and/or acquired all of the resources necessary to serve the vast majority of its forecasted load over the next several years, a significant impact fee is necessary to protect remaining customers from being assigned an undue amount of those sunk costs. Next, NV Energy, as a part of Berkshire Hathaway, is in an arguably better position that any potential exiting customer to obtain competitive energy prices. Also, NV Energy far exceeds its Portfolio

Standard requirements, and with renewable prices at historical lows, there is very little benefit to the system and remaining customers, from a Portfolio Standard perspective, of a customer departing under NRS 704B. As for load growth, Staff disagrees with the position taken by some NRS 704B applicants that once load growth has developed such that it equals the load of the departing customer, the analysis period should stop. Such a position is not in the public interest as the benefits of load growth should be shared by all entities, and not accrue solely to those entities able to depart via NRS 704B. Further, load growth does not always lower costs for remaining customers. When new capacity additions are needed to serve growth and those additions are more expensive than the utility's embedded cost, load growth may result in increased costs. (Ex. 11 at 4-8.)

34. Staff opines that, given current market conditions, there should be a minimum impact analysis period for all departing customers regardless of size. A minimum analysis period avoids the situation where every customer argues for a different analysis period because of minor differences in their load size or profile and minor differences in future load growth projections and market prices. A minimum analysis period also avoids previously-departed customers petitioning the Commission for reassessment of their impact fee because they believe a subsequent departing customer was given a better deal. (Ex. 11 at 9.)

35. An impact fee analysis period longer than six years also suffers from problems. Staff opines that a longer impact fee period starts to get into issues of whether the customer would have remained a customer of the utility had it not departed. This is a reason why Staff supports the R-BTER being collected through a non-bypassable charge as that rate is only charged on the energy consumed by the departing customer and is not a pre-payment of what would have been forecasted to be paid had the customer remained as a bundled retail customer.

A longer impact fee period also requires more assumptions regarding future BTGR, DOS, and Federal Energy Regulatory Commission ("FERC") transmission rates, increasing the risk of error. Further, per NAC 704B.410, the NRS 704B process seems to acknowledge that over time, NPC has some ability and obligation to mitigate costs as a result of a departing customer leaving bundled retail service. For example, NPC could reduce or consolidate major account representatives and allocate more costs and employee time to the transmission function. A longer impact fee period would remove some incentive for NPC to mitigate costs. Staff does acknowledge that a longer impact fee period may be needed if all future load growth made predevelopment departure filings. However, at this time, Staff is recommending the removal of all speculative credits from the impact analysis such as off-system sales. (Ex. 11 at 8-9, 12-13.)

36. Staff does not support NPC's proposal to set the BTER component of the impact fee analysis to zero in years when the analysis shows that Georgia-Pacific's departure lowers energy and capacity prices for remaining customers. Georgia-Pacific's departure would reduce the amount of power NV Energy will need to procure and/or produce in future years. Staff's impact fee uses NPC's own fuel and purchased power forecast; therefore, NPC's proposal to zero out the benefits that are forecasted to accrue seems unreasonable and unequitable. Staff does understand NPC's concern that under Staff's analysis, all future generation placeholders are removed and replaced with market purchases. However, Staff does so to avoid resource planning arguments in NRS 704B proceedings. By zeroing out all BTER benefits, NPC is assuming that if Georgia-Pacific's load stayed on the NPC system, NPC could serve that load at extremely low costs, if not zero cost via market purchases or the development of new generation resources. (Ex. 11 at 10-12.)

37. NPC also recommends that the time period over which the R-BTER is collected be lengthened to the life of the underlying contracts from the six-year period recommended by Staff. Staff opines that this issue is a policy decision for the Commission. If all future load growth large enough to exit the system under NRS 704B were to make predevelopment departure filings, a longer R-BTER period may be needed to protect ratepayers from potential future cost impacts. (Ex. 11 at 12.)

38. Staff disagrees with NPC's position that Georgia-Pacific's application does not add capacity, energy, and/or ancillary services to the State of Nevada. Early NRS 704B applications in 2002 and 2003 did not involve construction of new generation in Nevada and NV Energy did not raise a similar argument in those cases that it does now. While Barrick Goldstrike did construct a new power plant as part of its NRS 704B application, subsequent Barrick NRS 704B applications did not involve the construction of new generation and NV Energy signed stipulations in those dockets. Staff does acknowledge that an original goal of NRS 704B was to add generation resources in Nevada, but Staff does not believe that such action was a litmus test for approval of an NRS 704B application. Rather, it was a consideration to be made when analyzing the overall merits of an application. Further, NV Energy has contracted for energy and capacity from out-of-state resources and has included those resources as energy and capacity in its resource plan and energy supply filings. Staff does not believe that it is reasonable to say that firm wholesale market purchases do not add energy, capacity, and ancillary services to the State. (Ex. 11 at 13-14.)

39. Staff does not agree that Georgia-Pacific's proposed transaction with Tenaska will impair system reliability or the ability of NPC to provide electric service to remaining customers. NPC has been able to reliably serve Georgia-Pacific's load for the last ten to twenty years via the

existing transmission system and Staff is unaware of NPC having any transmission import constraints. (Ex. 11 at 14-15.)

40. Staff recites that Nevada's RPS (NRS 704.7801 through 704.7828) requires each provider of electric service to generate, acquire, or save a certain percentage of its retail sales using generation from renewable resources and/or savings from energy efficiency resources. Renewable energy generation and energy efficiency savings are registered and tracked in the form of portfolio energy credits ("PEC"), which is the equivalent of one kWh of retail sales with one kPEC being equivalent to one MWh of renewable energy or energy efficiency. (Ex. 9 at 2.)

41. In 2018, NPC will carry forward a surplus of 5,261,130 kPECs, of which 814,448 kPECs will be generated from renewable facilities and approximately 4,446,682 million kPECs will be from DSM programs. As Georgia-Pacific was a bundled retail customer when the PEC surplus was created and subsequently paid for the cost of renewable DSM PECs through prior BTER, TRED, REPR, and EEPR charges, Staff recommends that Georgia-Pacific take a portion of the surplus PECs upon departure. Staff proposes a proportional share of surplus PECs based on Georgia-Pacific's load ratio. Staff suggests that the calculation be done in conjunction with NPC's 2019 filing of its annual report for Portfolio Standard compliance for calendar year 2018. (Ex. 9 at 4, AC-2.)

42. Staff also recommends that Georgia-Pacific be responsible for a load ratio share of NPC's obligation to repay borrowed non-solar PECs owed to SPPC. The calculation should be made in conjunction with NPC's 2019 filing of its annual report for portfolio standard compliance for calendar year 2018. Georgia-Pacific's share of owed PECs to SPPC should be divided into three equal installments that may be subtracted from the annual transfers of non-solar R-BTER PECs allocated to Georgia-Pacific for 2019, 2020, and 2021. Georgia-Pacific's

allocation of PECs should be made on an annual basis because Georgia-Pacific's load ratio and the amount of R-BTER and REPR PECs generated fluctuate each year. The allocation of R-BTER and REPR PECs should be made annually after year-end so as to avoid the need for a true-up mechanism. Staff recommends that the duration of annual PEC allocations should mirror the time period for which each non-bypassable charge is paid. (Ex. 9 at 5-7, AC-4.)

Georgia-Pacific Rebuttal

43. Georgia-Pacific disagrees with BCP and Staff that it should not receive an off-system sales credit to its impact fee. Georgia-Pacific states that the risks of off-system sales is more appropriately addressed in the context of NV Energy's IRP. The value Staff assigns to the off-system sales credit is relatively small, just $34,000. The reason the amount is small is due to the model used to evaluate Georgia-Pacific's exit. The model uses a displacement study, comparing scenarios with and without Georgia-Pacific's load in order to calculate a marginal cost value to assign to the departing load. By restricting incremental sales, the displacement is limited to backing down generators or avoiding a market purchase. The reason the credit is small is because the variable cost of the marginal generation resource, which is being displaced in lieu of market purchases as a result of Staff's modeling adjustment, is often very close to the forecast market prices in the model. (Ex. 13 at 5-6.)

44. Georgia-Pacific's departure from cost of service rates does not pose a material risk with respect to incremental secondary sales. Even under the worst-case scenario where no incremental sales are realized as a result of Georgia-Pacific's departure, the variance is just $34,000, or $5,667 of sales revenue per year. It is unlikely that amount would produce any rate impact. Larger departures than Georgia-Pacific may pose a larger risk, but that is not the case with this Application. (Ex. 13 at 6-7.)

45. Georgia-Pacific states that NPC makes several new arguments in this case and some that have been rejected in previous NRS 704B cases. Georgia-Pacific disagrees with NPC's arguments. (Ex. 13 at 7-8.)

46. Georgia-Pacific contends that its Application is not deficient in terms of the 10-percent contract. Georgia-Pacific will provide the contract pricing information necessary to administer the 10-percent contract requirement in a compliance filing consistent with NAC 704B.370 and past Commission practice. The 10-percent contract is a material term of the electric service agreement that Georgia-Pacific is negotiating with Tenaska and the final agreement will comply with the requirement. Georgia-Pacific argues that NPC's interpretation that the 10-percent contract information be provided in the NRS 704B application is a misreading of the requirement. Georgia-Pacific states that the 10-percent contract information may be provided as a compliance item. This notion is supported by NAC 704B.370(5), which allows the Commission to condition its approval of a NRS 704B application on submission of a copy of the complete and executed contract between the eligible customer and its provider. (Ex. 13 at 11-12.)

47. NPC also contends that Georgia-Pacific's application is deficient with regard to information about the cost impacts of the transaction. Georgia-Pacific states that the entire point of the impact analysis is to determine the cost impacts for the utility and remaining customers. Staff prepared such an analysis and Georgia-Pacific has reviewed such and offered an alternative analysis. NPC's position is inaccurate. (Ex. 13 at 12-13.)

48. NPC argues that it will incur a cost in the form of carrying charges on Georgia-Pacific's impact fee. Georgia-Pacific states that interest appropriately accrues on the impact fee

balance in ratepayers' favor because the fee will not be reflected in rates until a later point. (Ex. 13 at 13.)

49. NPC argues that Georgia-Pacific has not provided information regarding the reliability impacts of its proposed transaction. Georgia-Pacific disagrees. The market transaction Georgia-Pacific proposes is a common power purchase agreement used within the western interconnect and similar to ones NV Energy has used in the past. Further, the transmission and distribution system has reliably accommodated Georgia-Pacific's load for many years. Georgia-Pacific will also comply with all regulatory requirements associated with ensuring reliable transmission access to its facility. (Ex. 13 at 14.)

50. NPC argues that Georgia-Pacific's proposed transaction does not constitute a new generation resource. Georgia-Pacific disagrees as it is well-established that market purchases are permitted under NRS 704B.310(6)(c) given that the Commission has rejected past arguments that a WSPP Schedule C market transaction is not a new energy resource for the purposes of NRS 704B. The terms of Georgia-Pacific's electric service agreement are irrelevant to whether market purchases are allowed under NRS 704B. Georgia-Pacific's provider may not purchase power from NV Energy to serve Georgia-Pacific's load. As such, the provider is inherently providing new resources to the State of Nevada. NV Energy's resource adequacy will improve as a result of the departing customer. NV Energy does not plan to dispose of any firm resources as a result of Georgia-Pacific's departure. (Ex. 13 at 15.)

51. Georgia-Pacific opines that introducing more participants into a regional power market is a good thing for all market participants, including NV Energy. More market participants should produce more efficient markets. NPC's argument would place it as the gatekeeper of new market entrants and the arbiter of when the utility is financially strong and

when it is not. Per Georgia-Pacific, that argument undercuts the role of the Commission, the Legislature, and NRS 704B. (Ex. 13 at 16-17.)

52. Georgia-Pacific also disagrees with NPC's proposal to lengthen the impact fee analysis period to ten years. While NPC contends that load growth is slowing, NPC does not quantify the degree to which load growth is slowing. Georgia-Pacific states that a shorter impact analysis period may be warranted as NV Energy is in the process of retiring significant amounts of generation. Nonetheless, Georgia-Pacific accepts Staff's recommendation of six years. (Ex. 13 at 17-18.)

53. Georgia-Pacific states that it is not clear what impact fee credits NPC proposes to remove from the impact fee calculation, nor its justification for doing so. Georgia-Pacific interprets NPC's position to zero out any year when the BTER impact is a credit to the departing customer. Georgia-Pacific contends that this proposal would undercut the very point of conducting the impact fee analysis. When a departing customer leaves, energy and capacity are freed-up, which provides value to the utility and remaining customers. This freed-up energy is offset by the fact that the departing customer is no longer contributing to fixed generation costs. The point of the impact analysis is to compare the offsetting impact of the freed-up energy and the lost contribution to fixed costs. Under NPC's proposal, zero value would be assigned to the energy freed-up by departing customers. (Ex. 13 at 19-20.)

54. Georgia-Pacific disagrees that it should be responsible for R-BTER costs beyond the six-year period. Singling out the R-BTER contracts and requiring the transition cost of those items to be calculated over the contract life is not reasonable because Georgia-Pacific would not receive any credit for any offsetting impacts beyond the five-year period. At some point, the NRS 704B customer's obligation for NPC's resource portfolio costs has to come to an end, and

if a six-year period is used for the impact fee calculation, a six-year period is appropriately used for all resources. (Ex. 13 at 20.)

Commission Discussion and Findings

55. Based on the evidence on this record, and for reasons that will be addressed in more detail below, the Commission finds, pursuant to NRS 704B.310(5), that it is not contrary to the public interest to approve Georgia-Pacific's Application and allow the account identified by Georgia-Pacific in its Application to depart bundled retail service; and the Commission orders, pursuant to NRS 704B.310(7)(b), a number of terms, conditions and payments that the Commission deems are necessary and appropriate to ensure that the proposed transaction will not be contrary to the public interest.

56. As a bundled electric service customer of NPC, Georgia-Pacific cannot purchase energy, capacity or ancillary services from a provider of new electric resources until it files an application with the Commission and the Commission approves the application. NRS 704B.310(1). Georgia-Pacific filed its Application pursuant to the provisions of NRS and NAC Chapters 704B.

57. Notably, NRS 704B.310(2) provides in relevant part:

> ... each application filed pursuant to this section must include:
> (a) Information demonstrating that the person filing the application is an eligible customer;
> (b) Information demonstrating that the proposed provider will provide energy, capacity or ancillary services from a new electric resource;
> (c) Information concerning the terms and conditions of the proposed transaction that is necessary for the Commission to evaluate the impact of the proposed transaction on customers and the public interest, including, without limitation, information concerning the duration of the proposed transaction and the amount of energy, capacity or ancillary services to be purchased from the provider; and
> (d) Any other information required pursuant to the regulations adopted by the Commission.

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