BEFORE THE UTAH PUBLIC SERVICE COMMISSION

In the Matter of the Application of Kennecott Utah Copper LLC for an Order Determining the Rates, Terms, and Conditions of Electric Service by Rocky Mountain Power to Kennecott	DOCKET NO. 23-035-51

REBUTTAL TESTIMONY

OF

KEVIN C. HIGGINS

On Behalf of

Kennecott Utah Copper LLC

April 19, 2024

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Kevin C. Higgins. My business address is 111 East Broadway, Suite 1200, Salt Lake City, Utah, 84111.

Q. By whom are you employed and in what capacity?

A. I am a Principal in the firm of Energy Strategies, LLC, a private consulting firm that specializes in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. On whose behalf are you testifying in this proceeding?

A. My testimony is being sponsored by Kennecott Utah Copper LLC ("Kennecott").

Q. Please summarize your qualifications.

A. My academic background is in economics, and I have completed all coursework and field examinations toward a Ph.D. in Economics at the University of Utah. In addition, I have served on the adjunct faculties of both the University of Utah and Westminster College, where I taught undergraduate and graduate courses in economics. I joined Energy Strategies in 1995, where I assist private and public sector clients in the areas of energy-related economic and policy analysis, including evaluation of electric and gas utility rate matters.

Prior to joining Energy Strategies, I held policy positions in state and local government. From 1983 to 1990, I was an economist, then assistant director, for the Utah Energy Office, where I helped develop and implement state energy policy. From 1991 to 1994, I was chief of staff to the chairman of the Salt Lake County Commission, where I was responsible for development and implementation of a broad spectrum of public policy at the local government level.

Q. Have you previously testified before the Utah Public Service Commission ("PSC" or "the Commission")?

A. Yes. Since 1984, I have testified in 49 dockets before the Commission on electricity and natural gas matters.

Q. Have you testified previously before any other state utility regulatory commissions?

A. In addition to these Utah proceedings, I have testified in approximately 240 other proceedings on the subjects of utility rates and regulatory policy before state utility regulators in Alaska, Arizona, Arkansas, Colorado, Florida, Georgia, Idaho, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, New York, North Carolina, Ohio, Oklahoma, Oregon, North Carolina, Pennsylvania, South Carolina, Texas, Virginia, Washington, West Virginia, and Wyoming. I have also filed affidavits in proceedings before the Federal Energy Regulatory Commission and prepared expert reports in state and federal court proceedings involving utility matters.

Q. Did you prefile direct testimony in this proceeding?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the Direct Testimony of Rocky Mountain Power ("RMP") witness Mr. Craig Eller regarding: (1) Schedule 31, Partial Requirements Service – Large General Service – 1,000 kW and Over, and (2) RMP's secondary rate proposal for

Kennecott. I also refer to the Direct Testimony of Office of Consumers Services ("OCS") witness Mr. Bela Vastag.

Q. Please summarize your primary conclusions and recommendations.

A. RMP's secondary proposal would require Kennecott to pay a fully allocated share of RMP's fixed costs of system generation resources, but imposes market risk that assumes Kennecott does not have access to system resources when market prices are high. If the Commission were to conclude that Kennecott should be treated as the "marginal customer" for some period of time, RMP's proposal is fundamentally flawed because it makes no effort to determine the true marginal cost to serve Kennecott nor does it propose to set rates that would recover its marginal cost of service. Instead, RMP proposes a "worst of both worlds" rate design: system average costs when market prices are low, depriving the marginal customer of the benefit of low market prices, and incremental marginal costs (in addition to fully-allocated system fixed costs) when market prices are high. RMP's proposal is asymmetrical, inherently unreasonable, and should be rejected.

II. SCHEDULE 31

Q. What is your understanding of the purpose of Schedule 31?

A. Schedule 31 provides Partial Requirements service to customers with onsite generation greater than 1,000 kW but not greater than 15,000 kW. Partial requirements service is distinct from standard full requirements service in that the former is provided to customers who have invested in self-generation facilities to serve all or a portion of their loads. Schedule 31 is made up of four types of service: backup, maintenance, supplementary, and excess. Backup service is intended to address customer demand for that portion of its total contract demand that is normally served by onsite resources, but for which utility service may be required when the onsite resources have an unscheduled outage. Supplementary service is intended to address the portion of service to the customer that will not be served by the customer's onsite generation resources. In the case of Schedule 31, supplementary power is provided at the customer's otherwise applicable rate schedule, *i.e.*, Schedule 8 or 9, according to RMP's tariff. A Schedule 31 customer's contract identifies the amount of Supplementary Contract Demand and Backup Contract Demand that applies to the customer. The total of these two is called the Total Contract Demand.

Maintenance service is intended to address backup service when the customer notifies the utility in advance of a maintenance outage related to its onsite generation resources. Excess service is demand utilized by the customer that exceeds the customer's Total Contract Demand.

Q. What do partial requirements rate schedules seek to accomplish?

For customers with onsite baseload generation, partial requirements service primarily provides backup power during forced outage or planned maintenance situations. This is an important consideration in rate design because it is unlikely that most of the onsite baseload units being backed-up by partial requirements service would be experiencing forced outages at the same time. Therefore, the rate design for this service should reflect this anticipated high degree of load diversity. It would be unreasonable to subject customers with onsite baseload generation to the same monthly demand charges as full-service customers for usage that is limited in nature because the utility does not need to plan to serve customers with onsite baseload generation in the same manner as full-service customers.

Schedule 31 appropriately addresses this concern through the use of daily demand charges when back-up power is needed, coupled with contractual Facility Charges that serve as charges for standby service.

Q. What is the nexus between Schedule 31 and Kennecott's request for Commission action in this case?

A. Schedule 31 describes the *type* of service that would apply if Kennecott were to return to standard tariff rates as requested, since Kennecott has onsite generation. However, as currently approved, Schedule 31 rates only apply to customers with onsite generation no greater than 15,000 kW. Currently, Kennecott has 39 MW of onsite thermal generation, consisting of a 31.8 MW nameplate cogeneration facility located at its smelter and a 7.54 MW nameplate combined heat and power facility located at its refinery, each of which is a Qualifying Facility ("QF") under the Public Utilities Regulatory Policies Act ("PURPA"). In addition, Kennecott has recently completed construction of a 5 MW solar generation facility that may be expanded to 30 MW. According to RMP's tariff, partial requirements service for customers with more than 15,000 kW of onsite generation must be provided under contractual arrangements to be negotiated on a case-by-case basis. Given this provision, there appears to be no published rate in RMP's tariff applicable to Kennecott, a rate vacuum that was duly noted by OCS witness Mr. Vastag.[1] For a customer in Kennecott's situation, the absence of a Commission-approved rate for service certainly

[1] Direct Testimony of Bela Vastag, lines 39-78.

impedes its ability to reasonably provide notice to RMP that it intends to withdraw its notice of intent to receive service from a nonutility energy supplier, since the rates that would apply to service from RMP to Kennecott are unspecified and according to the tariff can only be negotiated with RMP, a monopoly supplier.

Q. Why is Schedule 31 unavailable to customers with more than 15 MW of onsite resources?

A. This restriction was included in a settlement agreement approved by the Commission in 2014 in Docket No. 13-035-196. In that docket, Schedule 31 was modified from a voluntary tariff for large customers with onsite generation to a mandatory tariff for partial requirements customers that satisfied certain conditions of the tariff.[2] Previously, Schedule 31 was a voluntary tariff for large customers with up to 10 MW of onsite generation. RMP proposed that Schedule 31 apply to all customers with up to 15 MW of onsite generation unless the customer's onsite generation resources satisfied the requirements of a QF, in which case no cap would apply.[3] RMP reasoned that onsite generation that satisfied the requirements of a QF would have high rates of use, would have maintenance schedules similar to RMP's owned-generation units, and would not be used for arbitrage purposes.[4] The docket was ultimately resolved pursuant to a settlement stipulation and the upper limit for onsite generation in Schedule 31 was set at 15 MW without the caveat related to

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[2] *See* Exhibit 3.1 (*In the Matter of the Application of Rocky Mountain Power for Approval of Revisions to Back-Up, Maintenance, and Supplementary Power Service Tariff, Electric Service Schedule 31*, Docket 13-035-196, Order Confirming Bench Ruling (July 23, 2014) at 3 (¶ 11)).
[3] *See* Exhibit 3.2 (Docket No. 13-035-196, Direct Testimony of Joelle Steward at lines 40-44).
[4] *See id*. at lines 160-170.

resources that qualify as QFs. As I noted above, Kennecott's onsite generation resources are QFs.

Q. Did you testify in Docket No. 13-035-196?

A. No.

Q. In your opinion, does a 15 MW limitation on Schedule 31 service makes sense from a ratemaking perspective?

A. No. I acknowledge that parties to the 2013 case entered into a stipulation and respect the fact that the Commission approved the stipulation that was presented to it. But from a ratemaking perspective, there is not a good rationale for not allowing a customer with a 31.8 MW facility, which is the largest of Kennecott's onsite facilities, to utilize the Schedule 31 rates. PacifiCorp has more than 18,000 MW of generation, either owned or under contract,[5] which is more than 500 times larger Kennecott's largest plant. There is no credible reason why partial requirements service could not be provided to Kennecott's onsite generation under the current standard tariff rates.

Moreover, if there is to be a size limitation on tariff availability, it would make more sense to apply it to each individual generator rather than the customer's cumulative onsite generation amount. Back-up power service is provided when the customer's onsite generation experiences a forced outage. Kennecott's onsite generation facilities are in separate locations and perform different functions. If back-up power is needed, it should not be assumed that both plants would be experiencing forced outages at the same time.

[5] PacifiCorp 2023 Integrated Resource Plan, Chapter 6, pp. 148-154.

In addition, it is not clear why Kennecott's 7.54 MW facility does not qualify for Schedule 31 service under the current tariff except for an interpretation of the tariff concluding that mere presence of Kennecott's 31.8 MW facility prevents the 7.54 MW facility from receiving back-up service. Such an interpretation does not seem reasonable.

Q. RMP asserts that Kennecott's Backup Contract Power must match the nameplate capacity of its onsite generation resources.[6] Do you agree?

A. No. RMP does not cite to Schedule 31 or any other source to support this assertion and does not explain why it believes the Commission should adopt this assertion. Nothing in the text of Schedule 31 supports the assertion that a customer's Backup Contract Power must match the nameplate capacity of its onsite generation. Schedule 31 does not prescribe the amount of Backup Contract Power a Schedule 31 customer must obtain. Critically, the Commission's Order in Docket No. 13-035-196 confirms this point:

> …[T]he Division was concerned that currently Schedule 31 is applicable to customers with onsite generation less than 10,000 kW, but those customers are not required to take service pursuant to that schedule. Under the revised Schedule 31 however, PacifiCorp is proposing to require, with a few exceptions, all customers with onsite generation to take power under the proposed Schedule 31. *The Stipulation addresses this concern in that customers have the flexibility to nominate as much, or as little, power to be included under this schedule*. The Division believes this flexibility makes the requirement reasonable. [7]

Q. Are there reasons why a customer's Backup Contract Power might be different than the nameplate capacity of its onsite generation resources?

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[6] *See* Direct Testimony of Craig Eller (RMP) at lines 323-328.
[7] Ex. 3.1 (Docket No. 13-035-196, Order Confirming Bench Ruling at 4-5. (July 23, 2014) (emphasis added)).

A. Yes. Certain onsite generation facilities, such as cogeneration facilities, are designed such that they operate in tandem with the customer load centers. When the customer's load center is not operating, then the customer facility also does not generate electricity. It is my understanding that this is the case for Kennecott's smelter operation. When the smelter is not operating, the smelter cogeneration system is not generating electricity. Instead, the loss of load from the smelter being down matches or exceeds the loss of generation. In this scenario, Kennecott does not require backup service from the utility to replace the lost capacity of the smelter's onsite generation facility because its load needs have been reduced. It would not make sense for the Company to reserve system capacity to match the Kennecott's onsite generation capacity in this scenario.

Further, to the extent that the smelter would require backup service if the smelter cogeneration facility were to experience a forced outage, the customer should have the option of reducing its load to remain within its Total Contract Power. Failure to cut load to remain within the Total Contract Power demand would trigger very high Excess Power Charges. As recognized in the Commission's 2014 Order, a Schedule 31 customer should have the flexibility to contract for the amount of backup power suitable to its circumstances, and not be obligated to contract for the full nameplate amount of its onsite generation, as RMP's proposal suggests.

Q. Should a customer with onsite solar generation be required to subscribe to Schedule 31 for Backup Contract Power to its solar facility?

A. No, not in Schedule 31's current form.

Schedule 31 is a vintage partial requirements rate designed primarily for customers with behind-the-meter *thermal* generation, such as gas-fired cogeneration. The design premise of Schedule 31 is that the partial requirements customer pays a monthly demand charge that recovers a portion of the otherwise applicable demand charge whether or not backup service is needed in a given month. For months in which the customer's facility experiences an unscheduled outage, the customer pays a daily demand charge (Backup Power Charge) that is derived from the otherwise applicable monthly demand charge. This type of arrangement works well for a customer that has thermal onsite generation, in that its unscheduled usage of the RMP system to replace its customer-owned generation is likely to be occasional, e.g., a few times a year. But it is not reasonably workable for a customer that installs onsite solar generation because, absent accompanying battery storage, such a facility would be subject to the Backup Power Charge every single day, because RMP's on-peak period lasts until 10 pm all year, well after the sun has set. Consequently, for onsite solar generation, Schedule 31 serves no practical purpose as it is currently designed. A customer that installs onsite solar generation may as well remain on its otherwise applicable rate schedule and pay the monthly demand charge associated with its net load. Whether a customer with onsite solar generation takes service under Schedule 31 or Schedule 9, it will fail to receive any credit for capacity avoidance even when its solar facility is operating during on-peak hours, unless its load also drops as the sun sets, since requiring RMP power during any 15-minute period during on-peak hours will subject the customer to the full demand charge, whether it is a daily demand charge (incurred every day per Schedule 31) or a monthly demand charge (incurred per Schedule 9). In short, both Schedule 31 and Schedule 9 are similarly unattractive options for a customer that installs onsite solar generation.

Q. Are there rate design options for partial requirements service that can reasonably accommodate onsite solar generation?

A. Yes. I designed and proposed such a rate in New Mexico that relies on time-of-use pricing to recover demand-related costs when backup power is needed for solar facilities. After significant litigation, collaboration, and compromise, a version of this rate design was ultimately adopted by the New Mexico Public Regulation Commission in the Southwestern Public Service Company service territory.[8] I am not proposing here that the scope of this proceeding be expanded to redesign Schedule 31 to accommodate onsite solar generation; rather, I am merely pointing out that I am very familiar with this issue and see no justification or public purpose in requiring a customer with onsite solar generation to take service under Schedule 31. Nor is there any good reason to count a customer's onsite solar generation toward its total onsite generation amount when considering whether a customer exceeds the size limitations in Schedule 31, as currently in effect.

III. RMP'S SECONDARY PROPOSAL

Q. What do you understand to be the basis for RMP's proposal in this docket?

A. RMP's general assertion in this docket is that it has not planned to serve Kennecott in 2026 or thereafter and that, as a result, providing service to Kennecott in 2026 and for some

[8] New Mexico Public Regulation Commission, Case No. 22-00155-UT, Final Order Adopting Certification and Adopting In Part Recommended Decision (June 14, 2023); Hearing Examiner's Certification of Stipulation (May 16, 2023).

period of time thereafter would increase the risk of incremental market purchases as compared to a scenario in which RMP does not serve Kennecott in 2026.[9] RMP asserts that Kennecott should pay the costs associated with those incremental market purchases.

RMP's position is that Kennecott—for some period of time—is the "marginal customer," or the customer that should be served at the incremental cost to RMP of providing service after it has served its other customers.

Q. Is RMP's proposal designed to recover its marginal cost to serve Kennecott?

A. No. RMP's secondary recommendation seeks to impose on Kennecott a fully-allocated share of all fixed costs *plus* the cost of market energy any time that cost is higher than Schedule 9 energy charges, irrespective of whether RMP requires market products to serve energy at such times.[10]

RMP's proposal would require Kennecott to pay a fully allocated share of RMP's fixed costs of system generation resources, but imposes market risk that assumes Kennecott does not have access to system resources when market prices are high. In short, even if the Commission were to conclude that Kennecott should be treated as the "marginal customer" for some period of time, RMP's proposal makes no effort to determine the true marginal cost of service nor does it propose to set rates that would recover its marginal cost of service. Instead, RMP proposes a "worst of both worlds" rate design: system average costs when market prices are low, depriving the marginal customer of the benefit of low market prices when they occur, and incremental marginal costs (in addition to fully-

[9] *See* Direct Testimony of Craig Eller (RMP) at 498-500 ("The Company does not have adequate time to acquire incremental resources to serve Kennecott's load in 2026 resulting in an increased risk of market purchases.")
[10] *Id.* at 567-571.

allocated system fixed costs) when market prices are high. RMP's proposal is asymmetrical, inherently unreasonable, and should be rejected.

Q. For Kennecott's onsite generation, does RMP propose a rate structure consistent with the structure in Schedule 31?

A. Yes. RMP's proposal utilizes the existing rate structure of Schedule 31 for onsite generation. Specifically, RMP proposes that Kennecott pay energy charges and supplementary and backup power charges, following the structure of Schedule 31, although RMP's proposal regarding the *amount* of each such charge differs from those set forth in Schedule 31.

Q. Do you believe that RMP's proposal regarding supplementary power is just and reasonable?

A. No, it would not be just and reasonable to require Kennecott to pay the "higher of" Schedule 9 energy rates or some measure of real-time market rates. RMP's proposal is particularly unjust and unreasonable given the fact that it seeks to impose the "higher of" energy charges *and also* seeks to impose the full demand charges required in Schedule 9 on Kennecott's supplementary load. I find RMP's proposal to be inconsistent with the Company's narrative. On the one hand, RMP contends that the Company has not planned for Kennecott's load and therefore cannot provide standard tariff rates to Kennecott for supplementary power. At the same time, the Company proposes to charge Kennecott the fully allocated cost of the very same generation fleet RMP maintains is not available to serve Kennecott.

If Kennecott is to be treated as the marginal customer because RMP has not planned to serve Kennecott, then Kennecott should pay the true marginal cost of service rather than the full fixed costs of generation resources that RMP says it has not planned to use to serve Kennecott. Conversely, if Kennecott is to pay the full fixed cost of generation resources like all other customers, then it should pay energy charges like any other customer.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.