BEFORE THE SOUTH DAKOTA PUBLIC UTILITIES COMMISSION

DOCKET NO. EL18-038

IN THE MATTER OF THE COMPLAINT OF ENERGY OF UTAH, LLC AND FALL RIVER SOLAR, LLC AGAINST BLACK HILLS POWER INC. DBA BLACK HILLS ENERGY FOR DETERMINATION OF AVOIDED COST

SUPPLEMENTAL TESTIMONY OF DARREN KEARNEY
ON BEHALF OF THE PUBLIC UTILITIES COMMISSION STAFF
April 30, 2020

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EXHIBITS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. State your name.

A. Darren Kearney.

Q. State your employer and business address.

A. South Dakota Public Utilities Commission, 500 E Capitol Ave, Pierre, SD, 57501.

Q. State your position with the South Dakota Public Utilities Commission.

A. I am a Staff Analyst, which is also referred to as a Utility Analyst.

Q. On whose behalf was this testimony prepared?

A. This testimony was prepared on behalf of the Staff of the South Dakota Public Utilities Commission.

Q. What is the purpose of your supplemental testimony?

A. The purpose of my supplemental testimony is to provide an update to certain positions and opinions provided in my direct testimony. Topics in this supplemental testimony include: 1) the Legally Enforceable Obligation (LEO) date, 2) additional resources that should be included in Black Hills Energy's (BHE's) avoided cost model, 3) use of a 2.0 percent inflation rate, 4) the proper avoided capacity cost, 5) integration costs, and 6) BHE's resource planning and the Long-2 case.

Q. Why did you need to file supplemental testimony?

A. After depositions of BHE witnesses, receiving additional discovery responses, and reviewing BHE's and Fall River's rebuttal testimony, I learned of new facts that should be accounted for in the avoided cost calculation. In addition, I am providing additional support for certain positions presented in my direct testimony that will likely be challenged at the hearing.

II. DATE OF THE LEGALLY ENFORCEABLE OBLIGATION (LEO)

Q. What was your position on the date of the LEO in your direct testimony?

A. In my direct testimony, I stated that if the parties do not agree on a LEO date, my position was that the LEO was established on August 14, 2018. This opinion was based on Fall River meeting certain development activities.

Q. How has your position on the date of the LEO changed?

A. If the LEO date is contested by either BHE or Fall River, my position would change slightly. One of the development activities I considered for determining if a LEO had been established was the date the interconnection feasibility study was completed. In my direct testimony I identified that the feasibility study was completed by the end of July 2018. This date was based on the testimony from Fall River's witness Mr. Vrba. Upon further research on the matter, I found that the feasibility study was dated August 16, 2018. Therefore, I believe that all necessary development activities, including an offer from Fall River to sell its energy and capacity, were completed by August 16, 2018, and that is the date the LEO was established.

At the time of writing this testimony, it my understanding that the parties agree to use the date of September 14, 2018, which is the date Fall River filed its complaint with the Commission. I am comfortable with this date since there were no changes to forecasts, resources, or assumptions that occurred between August 16, 2018 and September 14, 2018.

Q. Why is the date the LEO was established important?

A. The date of the LEO is important since the assumptions included in BHE's avoided cost calculation are based on what was known at that time. This means that all resource decisions made by BHE, forecast changes, and other assumption changes that occurred after the LEO date should not be accounted for in the avoided cost calculation.

Support for establishing the assumptions as of the date the LEO was established can be found in FERC's implementing regulation for PURPA at 18 CFR § 292.304(d), which states:

> "(d) Purchases "as available" or pursuant to a legally enforceable obligation. Each qualifying facility shall have the option either:
>
> (1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or
>
> (2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:
>
> (i) The avoided costs calculated at the time of delivery; or
>
> (ii) ***The avoided costs calculated at the time the obligation is incurred***." **{emphasis added}**

The emphasized section of the regulation above identifies that the avoided cost is to be calculated at the time the obligation is incurred, should the QF choose to provide energy or capacity pursuant to a legally enforceable obligation.

III. ADDITIONAL RESOURCES THAT SHOULD BE INCLUDED IN BHE'S AVOIDED COST CALCULATION

Q. If the LEO date is September 14, 2018, does this change the resources included in the avoided cost model?

A. Yes. Based on the information that was known on September 14, 2018, it is my opinion that two additional resources should be included in the model. Those resources are a 12 MW PPA for the Silver Sage wind farm and 20 MWs of generation from SD Sun.

Q. Why should the 12 MW PPA for Silver Sage be included in the model with a September 14, 2018, LEO date?

A. During deposition of BHE's witness Mr. White, I learned that BHE had executed a PPA for 12 MWs from Silver Sage in August of 2018. This resource was not included in the avoided cost models produced by BHE. I obtained a copy of the PPA from BHE in discovery and the PPA was executed on August 16, 2018. Therefore, this resource was known at the time the LEO was established and should be included in BHE's avoided cost model.

Q. If the Commission determines that the LEO was established on your proposed date of August 16, 2018, what impact would that have on the inclusion of the 12 MW Silver Sage PPA in the avoided cost model?

A. Since the PPA was executed on August 16, 2018, and the LEO was established on or after August 16, 2018, I think it is reasonable to include the 12 MW Silver Sage PPA in the avoided cost model.

Q. Why should the SD Sun solar project be included in the model?

A. After further consideration of the principle behind establishing a LEO, it is my opinion that the Commission should only consider what was known at the time the LEO was established. According to BHE's ten-year plan filed with the Commission on July 29, 2018, BHE identified that the company had purchased the development rights for up to 52 MWs of a solar generator that was in the early stages of development with the potential commercial date of September 2019.

It is my understanding that while negotiating the PPA price for Fall River in the summer of 2018, BHE informed Fall River that only 20 MWs of the SD Sun project acquisition was planned to be constructed. BHE's witness, Mr. White, identified in his rebuttal testimony that "[b]y August of 2018, Black Hills believed that a 20 MW project was more likely, so it changed the amount of expected solar generation to reflect that progression in its resource planning." Mr. White then went on in his rebuttal testimony to explain that on March 1, 2019, BHE notified the parties in this case that the company did not intend to construct SD Sun.

Upon reviewing the timeline above, at the time the LEO was established BHE was planning to construct 20 MWs of solar from the SD Sun acquisition. Black Hills' official decision to not construct the 20 MWs was made in spring of 2019, well after the LEO was established. Based on this timeline, it is my opinion that what was known at the time the LEO was established was that BHE intended to construct 20 MWs of SD Sun generation and, therefore, that resource should be included in the avoided cost model.

Q. If the 12 MW Silver Sage PPA and 20 MWs of SD Sun are included in the avoided cost model, what impact will that have on the calculated avoided cost?

A. Adding in the two resources will lower both the avoided energy cost and avoided capacity cost. At this time, I do not know the exact impact on the avoided energy cost since BHE will need to rerun the avoided cost model with the additional resources. The impact on the avoided capacity cost is discussed later in this testimony.

IV. USE OF A 2.0 PERCENT INFLATION RATE

Q. In your direct testimony you recommend the use of a 2.0% escalation rate to account for inflation. Is this still your recommendation?

A. Yes.

Q. Please explain why you think a 2.0% inflation rate is reasonable to use.

A. I believe a 2.0% inflation rate is reasonable because the Federal Open Market Committee (FOCM) identified in its Statement on Longer-Run Goals and Monetary Policy Strategy that the target inflation rate is 2.0%. I attached the FOCM's statement as Exhibit_DDK-8.

Q. Please explain why you think BHE's 1.5% inflation rate is not appropriate to use for avoided cost modeling.

A. Avoided cost modeling is done for a future 20-year time period and the use of recently observed inflation rates in the current economic environment may not be representative of what will occur over the long run. It is my understanding that BHE's decision to use a 1.5% inflation rate is based on their current corporate policy for budgeting purposes in the present economic conditions. While that rate may be appropriate for a shorter-term corporate budgeting period, I find that it is not appropriate for a longer-term avoided cost model. Since the Federal Reserve will adjust monetary policy to try to achieve the 2.0% target rate, my expectations are that in the long run inflation will average around that target rate.

Q. Please explain why you think Fall River's proposed 2.45% inflation rate is not appropriate to use for avoided cost modeling.

A. As discussed above, monetary policy will be adjusted by the Federal Reserve to achieve the target inflation rate. If there are sustained periods of time with inflation over 2.0%, then my expectation is that the Federal Reserve will adjust monetary policy to bring inflation back near the target rate. As such, using 2.45% as an inflation rate for a long-term avoided cost model is higher than what is expected to be an average inflation rate over the long-term as the Federal Reserve's monetary policy has time to average out near the target rate.

V. Avoided Capacity Cost

Q. In your direct testimony you recommend using the cost of new entry (CONE) to calculate avoided capacity costs. Is this still your recommendation?

A. Yes.

Q. Why do you not support the use of firm energy purchases for meeting BHE's capacity deficiency as proposed by BHE?

A. There are several reasons why I think CONE should be used for calculating BHE's avoided capacity cost instead of firm energy purchases. First, BHE has not produced a bona-fide offer from another utility that demonstrates firm energy purchases can be procured at the prices included in the model. Second, BHE's historic firm energy purchases were not unit contingent. Third, I have concerns that the industry's transition to wind and solar resources will cause the need for flexible capacity resources in the future. Fourth, energy and capacity are two distinct electricity products that should be priced separately, especially as energy market prices decrease due to the increasing amounts of low marginal cost renewable energy resources. Finally, the Commission has historically used either a bona-fide capacity contract or CONE for establishing avoided capacity costs in past avoided cost dockets.

Q. Why do you need to see a bona-fide offer from a utility selling firm energy over the PPA term in order to support firm energy purchases?

A. Black Hills estimates the cost of future firm energy purchases using the energy price forecast produced by ABB for the Palo-Verde trading hub and then adding a 20% premium to that forecasted price. The 20% premium used by BHE is based on the company's experience with bilateral trading. In response to a Staff Data Request, BHE identified that the company does not have experience trading in periods of time when the Western Electricity Coordinating Council (WECC) region is capacity constrained. Therefore, I have concerns that if the WECC region becomes capacity constrained at some point during the PPA term the 20% premium may not be reflective of the cost of firm energy. Without a bona-fide offer from another utility for firm energy purchases over the 20-year period, I have no support to present to the Commission that the firm energy purchases with a 20% premium added to forecasted energy prices are in fact reflective of BHE's avoided capacity cost during the PPA term.

Q. Since BHE does not have a current bona-fide offer for firm energy purchases, does this mean the company will not purchase firm energy in the future to meet seasonal, short-duration capacity deficits?

A. Not necessarily. Black Hills' practice has been to procure seasonal, 6 x 16, firm energy purchases to meet small, short-duration, capacity deficits like those found in the current avoided cost modeling. Black Hills may continue with this practice if firm energy is available in the market and it is more economical to purchase than building its own peaking generation. However, that decision is typically made each year using near-term price forecasts that have a higher certainty than the longer-term price forecast that is used in avoided cost modeling. In addition, a near-term outlook on capacity resources available in the market would identify if excess capacity is available in the region to produce the needed firm energy.

I would be comfortable with basing avoided capacity costs on firm energy purchases over the next 1-3 years since market price forecasts are more certain and there is a more defined picture of capacity available in the WECC region. I am not comfortable with basing an avoided capacity cost on seasonal firm energy purchases in years 4 through 20 since price forecasts become more uncertain and the picture of available capacity becomes blurrier.

Q. Why do you have concerns that BHE's historic firm energy purchases were not unit contingent?

A. In response to a Staff Data Request, BHE identified that the seasonal firm energy purchases are not unit contingent. This means that the seasonal firm energy procured by BHE is not tied to a specific generating resource. My concern arises from the fact that the firm energy purchase is not tied to capacity reserved at a specific generating unit and it is therefore unknown if the utility selling the firm energy has used that same capacity to meet its own resource adequacy requirements.

In the WECC region, ensuring resource adequacy has been left to the individual utilities, with oversight from the states. At the present time I am not aware of any requirements in the WECC that requires unit contingent firm energy purchases to be used by a utility to meet its resource needs. Black Hills has taken advantage of this to generate savings for its customers. Even so, I am concerned about this practice from a resource adequacy perspective in the future.

As an example, if BHE joins a regional transmission organization (RTO) then the company's current process for purchasing firm energy that isn't unit contingent may not be allowed. It is my understanding that RTOs require firm energy purchases to be tied to reserved capacity of a specific generating unit. I have attached SPP's Resource Adequacy Tariff as Exhibit_DDK-9. Sections 7.4 and 7.5 in the document identify that the RTO needs to be able to verify that the capacity of the generator being used for firm energy purchases to meet a utility's resource adequacy obligation is not being used by another utility for resource adequacy purposes. Based on this, I am not confident BHE's firm energy purchases would qualify for meeting its resource obligations in the future.

Q. Why are you concerned about the industry's transition to renewable resources and the potential need for additional peaking resources?

A. The industry is currently undergoing a transition from traditional baseload generating resources to renewable resources. This means that dispatchable baseload coal plants are retiring or are being scheduled to be retired early. New generating resource additions replacing the traditional baseload plants are wind, solar, and gas. Wind and solar resources are non-dispatchable and intermittent. Given this, I find it difficult to believe that those resources will be used as a generating resource for firm energy contracts in the future.

Natural gas generating resources are dispatchable and may be able to provide firm energy, however they can be right-sized to a specific utility's capacity deficiency. As such, overbuilding new resources for the utility to "grow into" may not be as common as it has been in the past. If overbuilding gas resources does not occur, then unit-contingent firm energy may not be as readily available in the future.

Finally, the retirement of baseload generation and the increase in wind and solar generating resources may result in the need for utilities to construct additional dispatchable capacity resources. What this means is that while there is available capacity in the WECC region today to cover BHE's firm energy purchases, there is the potential that the WECC region will not have the same capacity surplus in the future. If excess capacity in the WECC region starts to diminish, I would expect BHE to look at constructing its own capacity resource to meet its resource needs. Therefore, I believe CONE is an appropriate assumption for capacity, especially for the later years of the avoided cost model.

Q. Why do you think it is important for energy and capacity to priced separately?

A. Energy and capacity are two distinct market products. Renewable energy resources like wind and solar produce low marginal cost energy that have decreased energy prices and will continue to do so as more renewable energy resources are brought online. Basing the cost of capacity on today's energy price forecast at a specific premium derived from recent experience may not be representative of the cost of capacity used for generating firm energy in the future. In other words, the premium BHE has determined to be reflective of securing firm energy today may not be reflective of the premium needed to secure firm energy in the future if the WECC region becomes capacity constrained.

It is my understanding that vendors produce separate, distinct forecasts for both energy prices and capacity prices. The forecast used by BHE for firm energy purchases is an energy price forecast. My general knowledge of capacity forecasts is that capacity prices tend to approach CONE at some point in the future as a result of needing to recover the cost of new investment. If the industry were to solely rely on energy prices to recover capacity costs, I would expect the on-peak energy price forecast to be much higher than the forecast used by BHE. The Electric Reliability Organization of Texas (ERCOT), for example, uses an energy only market for recovering the costs of new plant investment. In order to be able to incentive new plant investment, ERCOT has set an energy scarcity price at $9,000/MWh. What this tells me is that the on-peak energy price forecast BHE uses does not factor in the cost of capacity since the energy prices are nowhere near the amount needed to recover the cost of new plant investment and, therefore, is not a proper proxy for a capacity price. If all utilities relied on firm energy purchases at a forecasted energy price that doesn't include capacity costs for resource adequacy purposes, as BHE has done, no new capacity would be built since the forecasted compensation at an energy price is inadequate to recover the cost of new generation.

Energy and capacity are two distinct market products, therefore it is my opinion that one product cannot be used as a proxy for the other.

Q. What has the Commission historically used for determining capacity costs?

A. In the recent past, the Commission has considered the proper capacity cost for long-term contracts in three different dockets. Two of the dockets were PURPA avoided cost disputes. The third docket involved establishing a proxy-price for certain PPAs a utility was required to enter for meeting Minnesota state standards.

In docket EL11-006, the Commission determined that the proper avoided capacity cost was based on a short-term capacity contract. The price set by the Commission was based on a bona-fide offer from a selling utility and specifically tied to capacity.

In docket EL16-021, the Commission determined that the proper avoided capacity cost was based on CONE. In that case, the utility argued that the capacity cost should be based on indicative pricing of a short-term capacity contract whereas the QF and Staff argued that it should be based on CONE. After considering the utility's forecasted capacity deficiency and the fact that a simple-cycle peaking plant is generally regarded as the next avoidable resource, the Commission found that CONE was proper to use.

Just recently, in docket EL16-037, the Commission approved a settlement between Staff and a utility that established a proxy price for certain PPAs. In that settlement, the proxy price for capacity of certain solar resources was set at MISO's CONE.

Q. If the Commission determines the use of CONE is appropriate, what would the avoided capacity cost be?

A. First, the avoided capacity cost would be dependent on the first year Fall River can become operational. It is my understanding that Fall River now believes it is unlikely that the project will reach commercial operation by December 31, 2020. Further the company stated commercial operation could be delayed until December 2021. Therefore, in my calculations I assumed that the first year for a potential avoided capacity cost payment would be 2022.

Second, the avoided capacity cost would depend upon the resources included in the model. If included in the model, the12-MW Silver Sage PPA would add 1.2 MWs of capacity to BHE's existing resources and 20 MWs of SD Sun would add 10 MWs of capacity to BHE's existing resources. I calculate the levelized avoided capacity cost at $4.11/MWh if both these resources are included in the model. This is the avoided cost price I support based on the date I believe the LEO was established.

If the 12-MW Silver Sage PPA and 20 MWs of SD Sun generation are not included in the model, then I calculate the levelized avoided capacity cost at $6.54/MWh.

If just the 12-MW Silver Sage PPA is included, then I calculate the levelized avoided capacity cost at $6.44/MWh.

My calculations are attached as Exhibit_DDK-10.

VI. Integration Costs

Q. What are integration cost?

A. In order to integrate solar resources with the power system, additional regulation ancillary services will need to be procured by either the QF or the utility. The regulation services are needed to respond to the fluctuation of energy production from the solar resources. Solar production will vary during sunrise, sunset, and periods of cloud cover.

Q. Who should be responsible for paying integration costs?

A. Since integration costs would not be incurred but for the QF, those costs should be paid by the QF in order to hold utility customers indifferent.

Q. Should integration costs be subtracted from BHE's final levelized avoided cost?

A. It depends upon how the PPA is structured. If the PPA places the burden on the QF to procure the necessary regulation ancillary services, then no adjustment needs to be made to BHE's avoided cost. However, if the PPA places the burden on BHE to procure the necessary regulation ancillary services, then an adjustment to the avoided cost is needed.

Q. If BHE is responsible for procuring the additional regulation ancillary services, how much should the avoided cost be adjusted by?

A. I have seen a wide range of estimates for solar integration costs. However, I believe using WAPA's regulation service charges for the WACM balancing area as a starting point would be appropriate. The charges were $0.292/MWh[1] in 2018 and would need to be escalated annually for the 20-year PPA term.

Q. Does the Commission need to make the adjustment to the avoided cost at this time?

A. The adjustment only needs to be made at this time if Fall River does not agree to procure, and pay for, the regulation services on their own behalf.

VII. <u>BHE's Resource Decisions and the Long-2 Case</u>

Q. Has BHE considered the Long-2 case for past company owned must-run resources?

A. For company owned resources that are must-run resources, I am not aware of BHE modeling the Long-2 case for determining whether or not a resource should be constructed.

The Corriedale wind farm is the most recent company owned must-run resource. The purpose of constructing the project is to supply energy to BHE customers that voluntarily signed up for the company's Renewable Ready Services Program. BHE did not conduct integrated resource planning to support this project given it was meeting a specific

[1] See Exhibit_DDK-11: WAPA Rate Sheet.

customer need. As such, no analysis was completed that valued the excess energy at $0/MWh.

Prior to Corriedale, Wygen III was the last must-run resource that was constructed by BHE. An integrated resource plan (IRP) was used to support the construction of that facility. For that IRP, BHE allowed excess generation to be sold into the market and, therefore, did not account for the Long-2 case now being proposed for Fall River.

Q. Has BHE considered the Long-2 case for recent must-run resource Power Purchase Agreements?

A. As noted earlier in my testimony, BHE entered a Power Purchase Agreement for an additional 12 MWs of generation from Silver Sage Wind Farm. BHE did not conduct any resource planning to support the acquisition of that PPA and, therefore, the Long-2 case was not factored into the decision to acquire that resource. In response to discovery, BHE justified the acquisition by stating the price of the PPA is below the utility's average system cost for the term of the PPA. I am not aware of an analysis completed by BHE that reviewed the amount of dump energy that may be produced as a result of the PPA.

Q. Based on how BHE has historically planned for and acquired resources in the past, do you still support how BHE modeled the Long-2 case for determining BHE's avoided energy cost associated with Fall River? If so, why?

A. I remain supportive of how BHE modeled the Long-2 case for the same reasoning discussed in my direct testimony. I will not belabor those points again in this testimony.

Q. Should BHE account for the Long-2 case in its own resource planning?

A. Yes. BHE should be completing IRPs in order to determine the most cost-effective solution to meet a forecasted need. In those IRPs, the amount of dump energy should be analyzed for each case studied in that plan. Further, the modeling should not allow for all excess generation to be sold into the market.

If BHE presents an IRP to the Commission for justifying the cost recovery of a resource that causes dump energy and values that energy at a forecasted market price, the company does so at its own risk. The Commission could find that a portion of that resource was not needed to meet BHE’s system load due to the dump energy and disallow a certain amount of cost recovery for that resource.

VIII. Conclusion

Q. Does this conclude your testimony?

A. Yes.