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

DIRECT TESTIMONY OF DARREN KEARNEY
ON BEHALF OF THE PUBLIC UTILITIES COMMISSION STAFF
August 9, 2019

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EXHIBITS

I. INTRODUCTION AND QUALIFICATIONS

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. What is your educational background?

A. I hold a Bachelor of Science degree, majoring in Biology, from the University of Minnesota. I also hold a Master of Business Administration degree from the University of South Dakota.

Q. Please provide a brief explanation of your work experience.

A. I have been at the SD PUC for over six years now. During my employment with the PUC, I worked on a variety of matters in the telecom, natural gas, and electric industries. The major dockets that I work on are PURPA avoided cost dockets, energy conversion facility siting, transmission siting, pipeline siting, wind energy facility siting and energy efficiency programs. I also work on matters involving the Midcontinent Independent System Operator (MISO), specifically wholesale electricity market issues, transmission cost allocation and regional transmission planning. I have attended a number of trainings on public utility policy issues, electric grid operations, regional transmission planning, electric wholesale markets, and utility ratemaking.

The relevant work experience I have that is specific to this docket is the review of docket EL16-021 (a QF avoided cost dispute) and training to use EGEAS software to run production cost modeling for utility planning. My work on docket EL16-021 provided me with an understanding of PURPA law, avoided cost modeling, and Commission precedent on PURPA. The training I received on EGEAS provided me with an understanding of production cost modeling and the inputs/assumptions that drive the models.

Prior to joining the PUC, I worked at Xcel Energy for eight years. Most recently, I worked at a coal-fired power plant and was responsible for environmental permitting and compliance for the plant. Briefly, my responsibilities involved ensuring that the facility complied with all environmental permits at the plant, which included a Clean Air Act Title V Air Permit, a Clean Water Act NPDES permit, and a hazardous waste permit. I also drafted reports on the plant's operations for submission to various agencies as required by permit or law. Before working at the coal plant, I worked in Xcel's corporate environmental services department and was responsible for ensuring Xcel's facilities complied with the Oil Pollution Act of 1990. This involved writing Spill Prevention Control and Countermeasure (SPCC) plans and training Xcel employees on those plans. During that time, I was also responsible for the company's Environmental Incident Response Program, which involved training Xcel employees on spill reporting and response, managing spill cleanups, and mobilizing in-house and contract spill response resources.

II. PURPOSE OF TESTIMONY

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 direct testimony?

A. The purpose of my direct testimony is to provided my opinion as to Black Hills Energy's (BHE) avoided cost. I will first explain PURPA and the Commission's history implementing PURPA. Next, I will discuss the status of the Legally Enforceable Obligation (LEO). I then discuss BHE's avoided cost model and assumptions and inputs. I specifically address the Long-2 Case and avoided capacity cost. Finally, I provide my understanding of transmission interconnection costs and renewable energy credits as they apply to this docket.

III. PURPA AND COMMISSION HISTORY

Q. What is PURPA?

A. PURPA was passed as part of the legislation known as the National Energy Policy Act. Under Sections 201 and 210, PURPA encouraged development of certain small power production and cogeneration facilities known as qualifying facilities (QF). Section 210 requires electric utilities to (1) purchase from qualifying facilities any energy and capacity which is made available, (2) to sell to any qualifying facility, and (3) to interconnect with the qualifying facility. The Federal Energy Regulatory Commission (FERC) issued regulations implementing PURPA Sections 201 and 210, including 18 CFR 292.304 (a) regarding the rates for purchase:

> (1) Rates for purchases shall:
>
> (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
>
> (ii) Not discriminate against qualifying cogeneration and small power production facilities.
>
> (2) Nothing in this subpart requires any electric utility to pay more than the ***avoided costs*** for purchases. {***emphasis added***}

Avoided costs are defined by FERC "as the incremental costs of electric energy, capacity, or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source."[1] The primary point of contention in this docket is the determination of the cost BHE can avoid by obtaining energy and capacity from Fall River Solar.

Q. Which FERC Order adopts regulations that implement Section 210 of PURPA?

A. FERC Order 69[2] adopts regulations that implement Section 210 of PURPA. I attached a copy of Order 69 to my testimony because the order includes FERC's rationale for using certain language in the implementing regulations.

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[1] 18 CFR 292.101(b)(6).

[2] See Exhibit_DDK-1 for FERC Order 69.

Q. Does FERC provide an interpretation of an electric utility's obligation to purchase all electric energy and capacity made available from qualified facilities with which the electric utility is directly or indirectly connected under PURPA in Order 69?

A. Yes. Except under certain specific circumstances, FERC reiterates this purchase obligation mandated by PURPA. However, FERC does provide some clarifying comments on how much utilities should pay for energy and capacity if the power is not required to meet the utility's total system load:

> "A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale."[3]

I will reference this interpretation by FERC in other areas of my testimony as I believe this guidance will help the Commission resolve some areas of contention.

Q. Did the Commission initiate an investigation of the implementation of FERC's PURPA rules?

A. Yes. While FERC issued regulations adopting PURPA sections 201 and 210, the law requires cooperative federalism where state regulatory commissions are responsible for implementing PURPA QF regulations consistent with FERC regulations. FERC rules require state public utility commissions to set rates for the host utility to purchase power from a QF for regulated utilities.

In Docket F-3365,[4] the Commission investigated how FERC rules should be implemented in South Dakota. I have listed some of the relevant findings that relate to this docket below and emphasized those I rely on for my testimony:

- The rates for purchases from a QF with a design capacity of more than 100 KW should be set by contract negotiated between the QF and the electric utility. The Commission agrees with the recommendations of all parties that the Commission should play a

[3] Federal Register Vol. 45 No. 38, page 12219, provides FERC's interpretation of an electric utility's obligation under Section 210(a) of PURPA.
[4] See Exhibit_DDK-2 for the Order from Docket F-3365.

minimal role in the negotiation of such contracts, a role limited to resolving any contract disputes which arise between the parties.

- Distinguishing between rates for purchases fixed by contract with a duration of less than 10 years ("short-term contract") and rates for purchases set by contract with a duration of 10 years or more ("long-term contract").

- The capacity credits included in long-term contracts should be made constant over the duration of the contract.

- *Both short-term and long-term contracts should include an energy credit based on the average hourly incremental avoided costs calculated over the hours in the appropriate on-peak and off-peak hours as defined by the utility*. {*emphasis added*}

- The Commission finds that 18 C.F.R Section 292.306 requires each QF to pay "any interconnection costs which the State regulatory authority … may assess against the qualifying facility on a non-discriminatory basis with respect to other customers with similar load characteristics". The Commission finds that an assessment of interconnection costs can only be made on a case by case basis.

- The interconnection costs should be levelized over the life of the facility. To require a QF to pay the entire cost of interconnection up front might present too great a financial obstacle, and tend to discourage development of cogeneration and small power production.

- *The capacity credits to be included in any purchase rates, whether contractual or otherwise, should be based on capacity actually avoided, and if the purchase does not enable a utility to avoid capacity costs, capacity credits should not be allowed*. {*emphasis added*}

- *The Commission does not read the FERC's rules to permit a utility to pay capacity costs where none are avoided.* To do so would have the effect of requiring the utility to pay twice for the same capacity and would thus impose added and unnecessary costs on the utility's other customers, contrary to clear congressional and FERC intent. {*emphasis added*}

Q. Are there any other past Commission decisions that provide guidance on implementing PURPA and determining an appropriate avoided cost?

A. Yes. The Commission has ruled on avoided costs in two past dockets, EL11-006 and EL16-021.

In Docket EL11-006, *In the Matter of the Complaint by Oak Tree Energy, LLC against NorthWestern Energy for Refusing to Enter into a Purchase Power Agreement* (hereinafter referred to as docket EL11-006), the Commission issued findings[5] in 2013 on many of the same PURPA issues that are present in this docket. While the facts and circumstances of this docket may be slightly different than docket EL11-006, I believe the following findings of fact and conclusions of law are instructive and I emphasized those relevant to this docket:

- Given NorthWestern's status as a vertically integrated utility with predominant reliance on its own internal generation at this time, the hybrid method employed by NorthWestern is the proper method to calculate avoided costs for NorthWestern's South Dakota system.

- *The appropriate contract term for the Project is 20 years*. {*emphasis added*}

- *Levelized avoided cost values are the appropriate values to use because they will produce a stable price that will better enable Oak Tree to finance the project*. {*emphasis added*}

- *The renewable energy credits associated with the Project should remain with Oak Tree*. Oak Tree will have access to the REC markets, and Oak Tree can market its RECs as it deems in its best interest. {*emphasis added*}

- The inclusion of carbon costs in the avoided cost calculations is not justified at this time due to the absence of any legislation that seems likely to pass that would establish such costs and is therefore too speculative to warrant inclusion in the avoided cost.

- The proper natural gas and electric market rates to use in the hybrid method reflect market conditions and projections as of February 25, 2011, the date on which a LEO was created.

- Oak Tree is entitled to a capacity credit for the facility's output commencing with the Project's coming online with the capacity value equal to 20% of the Project's after-losses capacity of 18.915 MW. The 20% value is the appropriate percentage since NorthWestern is a member of the Midwest Reliability Organization (MRO), and as of the LEO date of February 25, 2011, the MRO accredited wind energy facilities at 20% of their rated capacity.

In Docket EL16-021, *In the Matter of the Complaint by Consolidated Edison Development, Inc. against NorthWestern Corporation dba NorthWestern Energy for Establishing a Purchase Power Agreement* (hereinafter referred to as docket EL16-021), the Commission issued findings[6] in 2017 on many of the same PURPA issues that are present in this docket. While the facts and circumstances of this docket may be slightly different than docket EL16-021, I believe the following findings of fact and conclusions of law are instructive and I emphasized those relevant to this docket:

- *The Commission finds that the appropriate model for determining NorthWestern's avoided costs is the PowerSimm model and that the model is not discriminatory to CED*

[5] See Exhibit_DDK-3 for the Amended Final Decision and Order for Docket EL11-006.
[6] See Exhibit_DDK-4 for the Final Decision and Order for Docket EL16-021.

since NorthWestern uses the model for the company's resource planning. {*emphasis added*}

- PowerSimm identifies three situations: (1) the hours that NorthWestern will be purchasing energy from the market to serve its load (Situation 1); (2) the hours that NorthWestern (a) has adequate resources to generate electricity to serve load, and (b) may reduce the output of its resources to follow load (Situation 2); and (3) the hours that NorthWestern (a) has adequate resources to generate electricity to serve load, and (b) may not reduce the output of its resources due to operational or contractual constrains (Situation 3).

- NorthWestern has certain generation units that cannot be backed down below a certain level. *Therefore, there may be times (Situation 3) at which the wind creates excess generation and will need to be sold into the market*. {*emphasis added*}

- The Commission finds that during Situation 1, NorthWestern can reduce its market purchases by purchasing the energy from a QF, and therefore, its avoided costs are market prices.

- The Commission finds that during Situation 2, NorthWestern can reduce the output of its resources by purchasing the energy from a QF, and therefore its avoided costs are the variable costs of operating the highest cost generating resource for which NorthWestern can reduce the output.

- *The Commission finds that during Situation 3, NorthWestern cannot avoid any costs by purchasing more energy, and therefore its avoided costs are zero*. {*emphasis added*}

- The Commission finds that NorthWestern has a need for capacity starting in 2019, and capacity payments for CED shall reflect 2019 as the beginning date for determining levelized capacity payment obligations. *The Commission further finds that the appropriate avoided capacity cost shall be based on the cost of a new simple cycle peaking plant.* The Commission further finds that the amount of capacity CED's projects will receive payment for shall be based on the SPP accredited capacity for each project. Finally, the Commission finds that CED shall be paid monthly for avoided capacity costs on a dollar per MWh rate $1.38 per MWh. {*emphasis added*}

- Wind generation projects require regulation support. In the SPP area, in 2015 the average cost of regulation for wind energy was $0.24/MWh. NorthWestern calculated the future annual cost per MWh of regulation by escalating the 2015 cost by the EIA Escalator. The Commission finds that this is a reasonable method of calculating the increased cost of regulation that the QFs will impose and that the QFs should be responsible for paying this cost. NorthWestern proposed deducting the annual cost per MWh of regulation from each year's average avoided cost in dollars per MWh. The Commission finds the NorthWestern's proposed deduction for incremental regulation is appropriate.

- Network upgrades are those items that are on the utility's side of the point of interconnection. These items are necessary for the interconnected operation of the QF. The Commission finds that due to the location of the CED's Projects, the network upgrades will not provide any additional reliability to NorthWestern's system. Further, the Commission finds that the QFs should pay for the network upgrades that are necessary for the interconnected operation and that do not provide any additional system benefit.

Q. Why did you identify and emphasize key findings from the Commission's order in dockets F-3365, EL11-006, and EL16-021?

A. In addition to analyzing this docket for meeting PURPA law and FERC's implementing regulation, I reviewed the Commission's history in order to understand how the Commission has interpreted PURPA in the past. I used these orders as guidance for developing certain positions provided in this testimony and will refer to certain past findings by the Commission as it relates to my opinions formed in this docket.

Q. Why is it difficult for Parties to agree on a proper avoided cost?

A. The definition of avoided cost is straightforward, but it can be difficult for Parties to agree on the costs an electric utility will avoid over a long period of time because it is an estimate based on forecasts. The estimate of future avoided energy costs over a long-term contract is primarily dependent on underlying assumptions about fuel and electricity market cost forecasts, and there are many different forecasts that stakeholders can use that yield significantly different avoided energy cost forecasts. In addition, natural gas and power price forecasts have trended downward in recent history, resulting in lower avoided costs for utilities and a challenging business environment for QFs under PURPA.

Q. Why is it important to establish a rate for purchase that does not exceed BHE's actual avoided cost?

A. BHE's customers will ultimately be responsible for paying the rate for purchase ordered by the Commission over the duration of the PPA. A fixed-price, long-term PPA effectively transfers much of the financial risk of the QF project from the developer to BHE customers. BHE's customers can be harmed by significant and unnecessary costs if the purchase rate exceeds BHE's actual avoided cost, which would be contrary to PURPA.

IV. Legally Enforceable Obligation (LEO)

Q. What is a LEO?

A. Under 18 CFR 292.304(d), FERC regulations allow each QF to have the option to either:

(1) provide energy as the QF 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) provide energy or capacity pursuant to a LEO for the delivery of energy or capacity over a specific term, in which case the rates for such purchases shall, at the option of the QF 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.

According to FERC Order 69, FERC used the term LEO to prevent a utility from circumventing the requirement that provides capacity credit for an eligible QF merely by refusing to enter into a contract with the qualifying facility. FERC has not defined what constitutes a LEO. Instead, FERC has provided state regulatory commissions the flexibility to define the requirements of a LEO consistent with PURPA and FERC regulations. The Commission has not defined what constitutes a LEO in rule and leaves the proper LEO date to be determined on a case by case basis.

Q. Why is a LEO significant?

A. If a QF elects to sell its power pursuant to a LEO based on a rate calculated at the time the obligation is incurred, PURPA requires that rates paid to the QF be set at the utility's avoided costs at the time the LEO is established. In this docket, Fall River has elected to have the avoided costs calculated at the time the LEO was incurred. Therefore, the underlying assumptions and forecasts to calculate the utility's avoided costs are based on the date the LEO was established. Assumptions and forecasts change over time as markets, technology, and policy changes. These changes could have material impacts on a utility's avoided costs.

Q. Has a LEO date been established in this case?

A. In order to limit the issues litigated before the Commission, the Parties agreed to stipulate to a LEO date of September 6, 2018. However, a formal stipulation memorializing the agreed upon LEO date was never filed with the Commission for approval. The LEO discussions took place before testimony was filed by Fall River and

BHE. I was surprised to see that both parties' testimony now indicates there may be contention on the LEO date. My review of this docket was under the assumption that the LEO date was stipulated to and is September 6, 2018.

Q. What is Fall River's position on the LEO?

A. I am not certain what Fall River's position is on the LEO date. In addition to September 6, 2018 (the date the Parties verbally stipulated to), Fall River also identified June 7, 2018, and August 14, 2018, as dates at which the LEO was established.

In its Complaint for Determination of Avoided Cost filed on September 14, 2018, Fall River identified that "a legally enforceable obligation in the sense considered by PURPA and the FERC regulations relating thereto was effectuated August 14, 2018." Fall River's justification for this date is that on August 14, 2018, Fall River committed to enter a Purchase Agreement with Black Hills at $41.66/MWh based on Fall River's calculation of BHE's avoided cost.

In Mr. Vrba's testimony filed on March 22, 2019, Fall River modified its position again and asserts that the LEO was formed on June 7, 2018. This is the date that Fall River sent BHE a Power Purchase Agreement (PPA) committing to sell BHE its energy and capacity at a price of $41.69/MWh based on the avoided cost rate BHE quoted 174 Power Global for SD Sun III.

Q. What is BHE's position on the LEO?

A. Mr. Kyle White identified in his direct testimony that BHE was willing to enter a stipulation on the LEO date of September 6, 2018. However, he noted that the stipulation was never finalized and that BHE now believes the Commission should adjudicate an appropriate LEO date, if any.

If the Commission does end up adjudicating a LEO date, BHE believes that Fall River has not yet triggered a LEO. BHE's rationale for its position is that Fall River never committed to deliver energy and capacity based on an avoided cost methodology that is consistent with the Commission's past decisions. BHE argues that Fall River only committed to deliver energy and capacity at a levelized price that assigns a forecasted market price to Fall River energy during hours in which BHE has no need for the energy to meet its total system load and cannot back down internal generation any further.

Q. What is your current position on the LEO?

A. In order to limit the issues before the Commission, I was not going to raise an issue with the stipulated LEO date of September 6, 2018. I was not aware of any parties having concerns with this date until I reviewed the testimony by BHE and Fall River.

Q. If the Commission adjudicates the LEO date, what is your position?

A. It is my position that a LEO cannot be established until the QF has committed to sell its energy and the QF has completed certain development activities.

Q. Please explain what "certain development activities" means.

A. In order for a QF to have the ability to obligate itself to sell and deliver energy to a utility, I recommend the QF must have: 1) acquired the land or obtained easements for the land that the generating facility will be located on, 2) obtained, or have the ability to obtain, all permits needed to construct the facility, and 3) completed an interconnection feasibility study. If the QF has not completed one of these activities, then the QF cannot know 1) if it can build the project in order to generate the power to sell to the utility or 2) if it can deliver the power onto the utility's transmission system.

Q. Is requiring the QF to have completed certain development activities unique?

A. No. FERC has left the determination of when a LEO is established to state commissions. My review of surrounding states identified that some commissions or rules require QFs to demonstrate that the QF has made substantial progress on the development of the project before being able to establish a LEO.[7] Those states have established criteria similar to the ones I set forth above.

Q. In your opinion, has Fall River established a LEO?

A. Yes. Fall River did commit to sell BHE its energy and capacity on June 7, 2018,[8] and then again on August 14, 2018.[9] Further, Fall River identified that it acquired an

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[7] Montana (ARM 35.5.1909) and MN PUC Docket E-017/CG-16-1021: *Order Establishing Date of Legally Enforceable Obligation, Term Length, and Avoided Cost of Energy for the Red Lake Fall Hybrid Solar/Wind Project (May 31, 2018).*

[8] *Direct Testimony of Ross Vrba* at 12:12-17.

easement in March of 2018 to construct the facility and that no planning and zoning permits are required by Fall River County.[10] Finally, Fall River identified that the transmission feasibility study was completed at the end of July 2018 and that study determined that Fall River could be interconnected with BHE's transmission system as a network resource without issue.[11] Therefore, Fall River has shown that it has the ability to build the project and deliver the energy.

Q. In your opinion, what date was the LEO established?

A. In my opinion, the LEO was established on August 14, 2018. This is based on when Fall River had completed the criteria for producing and delivering the energy (which I discussed earlier) and when Fall River committed to sell its energy through a tendered Purchased Power Agreement after that criteria had been met. Since the feasibility study was not completed by June 7, 2018, Fall River could not have committed to sell and deliver its energy to BHE since it was unknown if there was enough capacity on the transmission system.

Q. Please explain why you disagree with BHE's position that a LEO has not yet been established.

A. BHE argues that the LEO has not yet been established because Fall River never committed to sell energy and capacity using a methodology consistent with the Commission's past decisions. Essentially, BHE's argument is that the price offered by Fall River was not representative of BHE's avoided cost and, therefore, the commitment to sell energy and capacity was not a bona-fide commitment. I disagree with this argument because a QF would never be able to establish a LEO if agreeing to a purchase price, or avoided cost methodology, was needed in order to create a LEO. This would run afoul of PURPA's and FERC's intent.[12]

There are several methods that can be used to determine a utility's avoided cost and QFs may want to litigate that before the Commission if they disagree with the utility's method. If this Commission had established the proper method of determining a utility's

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[9] *Id.* at 13:11-17 and *Complaint for Determination of Avoided Cost* ¶26.
[10] *Direct Testimony of Ross Vrba* at 9:1-11 and 9:18.
[11] *Id.* at 15:10-18.
[12] "Use of the term 'legally enforceable obligation' is intended to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with qualifying facility." Federal Register Vol. 45 No. 38, page 12224.

avoided cost in rule, then I may find BHE's argument more persuasive. But that is not the case here since the Commission has left the proper avoided cost method to be determined on a case by case basis.[13]

Q. Is the stipulated LEO date of September 6, 2018, or your proposed LEO date of August 14, 2018, consistent with the Commission's past decisions?

A. Yes. Regarding the stipulated date of September 6, 2018, this aligns with the Commission's decision in docket EL16-021, where the Commission set the LEO date based on the date the QF filed its complaint with the Commission. Fall River filed its complaint on September 14, 2018, which is close to the September 6, 2018, stipulated date. I do not believe the stipulated date vs. the date Fall River filed its complaint will materially impact, if at all, the final avoided cost established by the Commission.

Regarding my proposed LEO date of August 14, 2018, this aligns with the Commission's decision in docket EL11-006. In that docket, the Commission found that the LEO was established when the QF sent its commitment letter to the utility. However, I will note that the Commission did not consider the additional development activities that would have given the QF the ability to generate and deliver the energy to the utility. While the method I used to determine my proposed LEO date is different from the Commission's analysis in docket EL11-006, my proposed LEO date is still based on when the QF committed itself to the utility through a tendered purchase agreement.

V. BHE's Avoided Cost Model

Q. What method did BHE use to model its avoided cost?

A. In order to determine its avoided cost, BHE used ABB's Enterprise Planning and Risk model (Planning and Risk). Planning and Risk is a production cost modeling tool that can be used to forecast a utility's production costs. BHE ran the model twice. BHE first ran the model without the QF included to determine BHE's forecasted production costs based on its current resources. The second time BHE ran the model they included the QF as a resource in the model to determine the forecasted production costs with the QF. BHE then subtracted the forecasted production cost of the model run including the QF

[13] Exhibit DDK_2: *Order from F-3365* at page 11.

from the model run excluding the QF to determine the production cost savings due to the QF. This result, or production cost savings, becomes the avoided cost.

Q. Is this an appropriate method to use for determining the avoided cost?

A. Yes. This type of modeling is form of the Differential Revenue Requirement method for determining avoided cost. It is my understanding that Fall River does not take issue with this method for determining avoided cost. Fall River does take issue with some assumptions BHE used, which will be discussed later in my testimony.

Q. Has the Commission approved a form of the Differential Revenue Requirement in the past?

A. Yes. In docket EL16-021, NorthWestern Energy used a similar method to determine its avoided cost, which the Commission approved. However, NorthWestern did use a different modeling software (i.e. PowerSimm) than what BHE used in this case (i.e. Planning and Risk).

Q. Do you have any concerns with the use of the Planning and Risk modeling software?

A. No. It is my understanding that BHE uses Planning and Risk for its own resource planning.[14] Since BHE uses Planning and Risk for both its internal resource planning and determining a QFs avoided cost, it eliminates one area of potential discrimination to the QF.[15] I am also under the impression that Fall River does not take issue with the use of Planning and Risk by BHE since the issue was not raised in Fall River's testimony.

Q. Are you familiar with production cost modeling?

A. Yes. I have been trained on using a production cost model, EGEAS, through the Organization of MISO States. I have not used Planning and Risk, however I would expect both models to operate similarly.

Q. Do you consider yourself an expert on production cost modeling?

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[14] Direct Testimony of Amanda Thames, 4:18-23.

[15] In docket EL16-021, the Commission found NorthWestern's use of PowerSimm was not discriminatory since the company used that modelling software for its own resource planning.

A. No. I am not testifying as an expert on production cost modeling. As such, I will not be submitting production cost modeling results. My training and experience allow me to understand the inputs and assumptions used in production cost models as well as what drives production cost modeling results. Therefore, I do consider myself qualified to provide an opinion on the inputs and assumptions used in BHE's production cost modeling.

Q. What key inputs and assumptions drive a production cost model?

A. BHE's witness Amanda Thames identified that they key assumptions driving the model are: (1) the load forecast for both demand and energy, (2) variable costs associated with the utility's owned resources, (3) attributes of the utility's owned generation characteristics (e.g. heat rate, ramp rate, unit minimums and maximus, and fuel type), (4) contractual purchase and sales, (5) unit availability, and (6) forecasted commodity prices including natural gas, oil, purchased power, and coal. Based on my experience with EGEAS, I agree that these are the key modeling inputs and assumptions that drive the model results.

Q. Did you review all the key inputs and assumptions used in BHE's avoided cost model?

A. Yes. The inputs and assumptions were provided to me through discovery. However, I focused my review for reasonableness on the load forecast and commodities price forecasts. These two assumptions can be reviewed for reasonableness using other resources. For the other assumptions (i.e. existing generator variable cost, existing generator characteristics, unit availability, and contractual purchase and sales), those are based on BHE's internal data and cannot be verified with external resources.

Q. What did you find in your review of the load forecast?

A. One area that a utility could discriminate against a QF is by adjusting demand and energy forecasts to suppress the avoided cost price. Therefore, the load forecast needs to be as accurate as possible and consistent with what is used for BHE's internal resource and reliability planning.

In the avoided cost model, BHE forecasts an annual growth rate around 0.8% for peak demand. This did not raise any red flags for me as this is comparable to peak demand forecasts of other electric utilties.

For energy growth, BHE forecasts an annual growth rate around -0.02%. This forecast did surprise me as I wasn't expecting to see a negative forecasted growth rate for energy. I reviewed BHE's most recent IRP (from 2011) and found at that time they were forecasting an energy growth rate of ~1.0% over the forecast period. In response to discovery, BHE acknowledged that they changed the forecast method from a historical look-back method (used for the 2011 IRP) to a weather-normalized econometric method (used in this docket) 3 years ago. The change in the load forecast method was based on a settlement between BHE and Staff in docket EL12-062.[16]

At this time, I do not fully understand the weather-normalized econometric forecast method used by BHE and I am reserving my position on the reasonableness of the energy forecast until I have a better understanding of that method. BHE should identify what economic variables were considered for use in the econometric load forecast and what economic variables statistically influenced the load forecast and ended up being incorporated into the econometric model. In addition, BHE should identify how energy efficiency savings were forecasted which also reduces the company's energy forecast. I recommend BHE address these items in its rebuttal testimony.

Even though the forecast method changed, there are other factors that influence a load forecast over time such as energy efficiency, distributed generation, economic growth, income, and population changes. I need to better understand the drivers behind the flat to negative energy forecast. In addition, I need to better understand how BHE forecasted the energy efficiency savings included in the forecast.

I did verify that the load forecast BHE used in the avoided cost model is the same forecast BHE provided to WECC. This check was for assessing possible discrimination

[16] Settlement Stipulation, PUC Docket EL12-062, *In the Matter of the Application of Black Hills Power, Inc. for the Phase in of Rates Regarding Construction Financing Costs of Cheyenne Prairie Generating Station.*

against the QF and it shows that BHE did not adjust its load forecast specifically for determining its avoided cost in this docket.

Q. What forecast did BHE use for natural gas and purchased power market prices?

A. BHE used the ABB 2018 Spring Reference Case forecast. Using the 2018 Spring Reference Case is reasonable since the LEO date was stipulated to being September 6, 2018. It is my understanding that the 2018 Fall Reference Case was not released until after the stipulated LEO date.

Q. Do you have any concerns with natural gas and purchased power market price forecasts?

A. I do not have any concerns with ABB's forecasts. ABB's forecasts are reputable and used by several utilities for integrated resource planning. However, the forecasts provided by ABB are in real dollars and BHE had to incorporate an inflation growth rate to the ABB forecast in order to convert the forecast to nominal dollars for the avoided cost modeling. Through discovery, BHE provided updated modeling results that account for the inflation adjustment and those results are the source for the numbers I use in my testimony.

Q. What inflation rate did BHE use to convert the ABB forecast to nominal dollars?

A. BHE used a 1.5% inflation rate.

Q. Do you have concerns with this inflation rate?

A. At this time, I do have concerns. In my opinion, BHE needs to better support an inflation rate of 1.5%.

Upon review of the Energy Information Administration's (EIA) natural gas price forecast that was provided in its 2018 Annual Energy Outlook, the inflation rate EIA expected for natural gas is greater than 1.5%. I formed this conclusion by subtracting the annual average growth rate of EIA's natural gas forecast provided in nominal dollars from the annual average growth rate of EIA's natural gas forecast provided in real dollars. In the 2018 AEO, EIA forecasted a 3.9% annual growth rate for 2017-2050 in nominal dollars and a 1.5% annual growth rate for 2017-2050 in real dollars. Therefore, I determined that the imbedded inflation rate in EIA's nominal dollar forecast was 2.4%. In MISO's

2018 Transmission Expansion Plan (MTEP 2018), they used an inflation rate of 2.5% (although it was not specific to gas and power forecasts). The inflation rates used by EIA and MISO in 2018 leads me to question BHE's 1.5% inflation rate.

With that said, BHE did identify through discovery that the 1.5% inflation rate is the standard corporate rate they use. I reviewed the inflation rate in the benefit-cost models for energy efficiency programs and found a 1.5% inflation rate used in those models. For BHE's 2011 IRP and the avoided cost modeling completed for SD SUN I, SD SUN II, and BHE's Purchase of the three solar projects, I could not determine what inflation rate, if any, was used for the natural gas and purchased power cost forecasts.

At this time, I find that BHE's use of a 1.5% inflation rate for the natural gas and purchased power market price forecasts is not discriminating against Fall River since it is the company's corporate standard rate. However, I question whether 1.5% is correct for natural gas and purchased power price forecasts.

Q. Do you have concerns with any other of the key inputs or assumptions BHE used in the avoided cost model?

A. The only concern I have with other cost inputs (e.g. variable O&M costs and coal price forecast) is the 1.5% escalation rate. I don't have any concerns with the costs or prices beyond the inflation rate, currently. Again, BHE needs to better support the 1.5% inflation rate and should do so in its rebuttal testimony. I do not have any concerns with outage forecasts, minimum generation levels, or the inputs used for contracted purchases and sales.

VI. <u>The Long-2 Case</u>

Q. Please explain your understanding of the Long-2 Case at issue in this docket.

A. The Long-2 Case, also known as Situation 3 in docket EL16-021, occurs during certain hours of the year when BHE's load is low and the company cannot back down its must-run resources below their minimum generation levels to accommodate the additional QF generation to meet its system load. Must-run resources cannot be shutdown to accommodate the QF generation without incurring additional cost (i.e. avoided cost would be negative).

Q. How does BHE's avoided cost model account for these hours?

A. Since both Fall River and certain BHE baseload plant minimum generation levels are modeled as being must-run resources, the model will have those plants generate energy no matter what the load is. If the total energy generated from the must-run resources exceeds the load, the amount of energy exceeding the load becomes excess energy.

There are two options for how the model can handle excess energy. The first is to run the model with "dump energy." This essentially identifies the amount of energy produced by the model that is not needed to meet the system load. Dump energy is not assigned a value and, therefore, is not included in the total system cost produced by the model.

The second option is to run the model without using dump energy. In this case the model will assume the energy is sold into the market and assigns the excess energy a market price based on the forecasts used. The model does this for each hour there is excess generation over the 20-year forecast period. The value of the market sales is incorporated into the total system cost and ultimately reduces the total system cost. What this means is that the avoided cost paid to the QF would increase because when comparing the QF-in/QF-out models the difference in system costs is greater than what the difference would have been if the excess generation was modeled as dump energy.

BHE assigned the excess energy as dump energy in the QF-in and QF-out models produced for determining its avoided cost and, therefore, did not value the excess energy based on the forecasted market price.

Q. Do you agree with modeling excess energy as dump energy?

A. Yes. I agree with how BHE modeled the Long-2 Case. In my opinion market price should not be assigned to hours when BHE cannot avoid any costs for its system by taking QF energy. Since BHE has no need for the QF energy to meet its system load in the Long-2 case, the value should be zero for those hours and modeled as dump energy.

Q. How do you justify this position?

A. Several ways. First, the QF's excess energy modeled as "dump energy" is consistent with the Commission's most recent QF avoided cost ruling in docket EL16-021. Second, in my opinion FERC Order 69 clearly states that the utility is not required to take QF energy and sell it to another utility. Third, FERC has provided guidance through declaratory orders on QF curtailment issues that identified the forecast developed at the time the LEO is incurred should factor in these low load periods. Finally, the avoided cost must be just and reasonable to the customer of the utility and in the public interest, which modeling dump energy does.

Q. How is BHE's Long-2 Case consistent with docket EL16-021?

A. In docket EL16-021, NorthWestern argued before the Commission that when the company has no need for the energy in the Long-2 Case, or Situation 3, the proper avoided cost to assign during those periods is zero dollars. Commission Staff also agreed with NorthWestern in that docket. The Commission ultimately found NorthWestern's and Staff's arguments persuasive and ruled:

- PowerSimm identifies three situations: (1) the hours that NorthWestern will be purchasing energy from the market to serve its load (Situation 1); (2) the hours that NorthWestern (a) has adequate resources to generate electricity to serve load, and (b) may reduce the output of its resources to follow load (Situation 2); and (3) the hours that NorthWestern (a) has adequate resources to generate electricity to serve load, and (b) may not reduce the output of its resources due to operational or contractual constrains (Situation 3).

- NorthWestern has certain generation units that cannot be backed down below a certain level. Therefore, there may be times (Situation 3) at which the wind creates excess generation and will need to be sold into the market.

- The Commission finds that during Situation 1, NorthWestern can reduce its market purchases by purchasing the energy from a QF, and therefore, its avoided costs are market prices.

- The Commission finds that during Situation 2, NorthWestern can reduce the output of its resources by purchasing the energy from a QF, and therefore its avoided costs are the variable costs of operating the highest cost generating resource for which NorthWestern can reduce the output.

- *The Commission finds that during Situation 3, NorthWestern cannot avoid any costs by purchasing more energy, and therefore its avoided costs are zero*. {*emphasis added*}

This is exactly how BHE is modeling Fall River's avoided cost in this docket and it is therefore consistent with the Commission's decision in docket EL16-021.

Q. How is BHE's Long-2 Case consistent with guidance provided in FERC Order 69?

A. As noted earlier, FERC's guidance in Order 69[17] is as follows:

> "A qualifying facility may seek to have a utility purchase more energy or capacity than the utility requires to meet its total system load. In such a case, while the utility is legally obligated to purchase any energy or capacity provided by a qualifying facility, *the purchase rate should only include payment for energy or capacity which the utility can use to meet its total system load*. These rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale." {*emphasis added*}

In this case, Fall River seeks to have BHE purchase more energy than what is needed to meet its system load. FERC's guidance on how to account for the excess energy, as emphasized above, provides that the energy payment only needs to account for energy BHE can use to meet its total system load. Dump energy in BHE's avoided cost model represents the amount of energy not needed to meet BHE's total system load. Since dump energy is not assigned a price, BHE's model does exactly what FERC's guidance says utilities should do in these situations.

FERC then even further clarifies that "[t]hese rules impose no requirement on the purchasing utility to deliver unusable energy or capacity to another utility for subsequent sale." In my mind this guidance from FERC clearly states that utilities are not obligated to take excess energy produced by a QF and then sell that energy to another utility. Therefore, BHE's inclusion of dump energy in its avoided cost model is consistent with this guidance provided by FERC in Order 69.

Q. How is BHE's Long-2 Case consistent with other FERC guidance?

A. In past FERC declaratory rulings and orders, FERC has consistently held that a utility cannot curtail a QF's generation during light load hours (especially for those QFs that decided to have the avoided cost determined at the time the LEO was incurred). When

[17] Exhibit_DDK-1 FERC Order 69 at Page 6 of 24.

providing its rationale for this, FERC has stated that it the utility's avoided cost rates calculated at the time the LEO is incurred should have already accounted for light load hours.

For example, FERC states in an *Idaho Wind Partners 1, LLC*[18] declaratory order:

> "Moreover, and in addition, we emphasize that in the case before us we are addressing sales pursuant to long-term PPAs, i.e., sales pursuant to "contractual or other legally enforceable obligations." In *Entergy*, as we similarly and earlier noted in Order No. 69, we observed that avoided-cost rates can reflect average or composite costs and thus already account for fluctuations in the value of the electric energy in the contractually-set price. We therefore reject Idaho Power's contention in this case that there is a factual dispute over the degree to which light loading was taken into account in its PPAs with Idaho Wind's subsidiaries. Instead, *the rates set in the PPAs for such bilateral transactions—which reflect avoided costs calculated at the time the obligations were incurred—already represent each party's taking into consideration various changes in circumstances over time such as light loading when deciding to be bound by the PPAs' terms*." {*emphasis added*}

And as referenced in the guidance above, FERC states in its *Entergy*[19] order:

> *"Many avoided cost rates are calculated on an average or composite basis, and already reflect the variations in the value of the purchase in the lower overall rate.* In such circumstances, the utility is already compensated, through the lower rate it generally pays for unscheduled QF energy, for any periods during which it purchases unscheduled QF energy even though that energy's value is lower than the true avoided cost. On the other hand, for avoided cost rates that are determined in real-time, such avoided costs adjust to reflect the low (or zero or negative) value of the unscheduled QF energy, allowing the QF to make its own curtailment decisions. In neither case is the utility authorized to curtail the QF purchase unilaterally." {*emphasis added*}

I read this guidance from FERC as meaning the avoided cost rate calculated at the time the LEO is incurred should account for the value of energy during light loading hours. When BHE has no need for energy to meet its total system load that value is zero.

In addition, FERC states in its rehearing order for *Idaho Wind Partners 1, LLC*[20]:

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[18] Idaho Wind Partners 1, LLC, 140 FERC ¶ 61,219 (2012).
[19] Entergy Services, Inc., 137 FERC ¶ 61,199 (2011).

> "*Order No. 69's reference to PPA parties' "ordinarily" taking price fluctuations into account does not mean that parties are entitled to re-negotiate PPA terms if they belatedly find that they did not take every type of price fluctuation into account.* Similarly, Idaho Power misconstrues P 56 of *Entergy Services*. In that case, we divided long-term PURPA PPAs into those with rates calculated at the time of delivery and those calculated at the time the obligation was incurred. *We explained that rates are calculated for "many" long-term PPAs at the time the obligation is incurred and that these incorporate price fluctuations. This does not mean that we envisioned PPAs with rates calculated at the time the legally enforceable obligations were incurred to have ignored the possibility of price fluctuations.*" {*emphasis added*}

I take this guidance from FERC to mean that utilities cannot later ask to re-negotiate a PPA if they find out that they failed to take into account certain price fluctuations. This means that the utility should ensure that light load hours are properly valued in the avoided cost price at the time of executing the PPA. This is exactly what BHE is doing in this docket. BHE is accounting for the light load hours in the levelized price of the PPA before being locked into a price.

Q. How is BHE's Long-2 Case just and reasonable to the customer of the public utility and in the public interest?

A. As a vertically integrated utility company, BHE does not rely on the market for all of its energy needs. BHE's customers are currently paying retail rates that recover significant generation resource investments. These investments in generation limit BHE's customers exposure to market price risk by capping the cost of energy at the variable cost of BHE's owned generation facilities. While Fall River's avoided cost methodology may be appropriate for a utility in a deregulated electricity market, it does not properly reflect the avoided energy cost of a vertically integrated electric utility.

In addition, BHE's modeling of the Long-2 Case specifically limits the payment for only the energy that BHE can use to meet its total system load. If market price was assigned to the hours in the Long-2 Case, BHE would be effectively serving as a market broker for Fall River, and BHE's customers would likely end up taking on the market price risk for energy that will not be used to serve them. In that case, there could be an unlimited number of QF developers that could obligate BHE to purchase energy not needed to

[20] *Idaho Wind Partners 1, LLC,* 143 FERC ¶ 61,248 (2013).

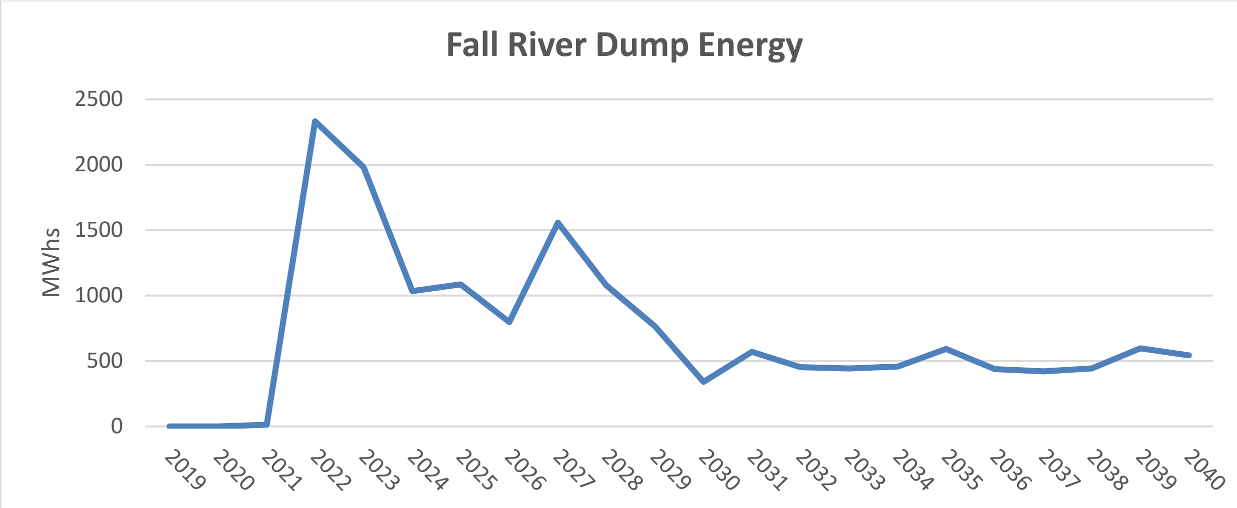
meet its system load at forecasted market prices. Failing to limit payment for only energy that is used to meet NorthWestern's total system load is inconsistent with FERC's interpretation of PURPA's purchase obligation and would not be just and reasonable to BHE's customers.

For further explanation, consider the following hypothetical situation demonstrating the impact of the Long-2 Case if excess energy is not modeled as dump energy, and rather assigned a forecasted market price, when determining a utility's avoided cost. Suppose BHE models its avoided cost price for a hypothetical QF and that model shows 100% of the energy produced is dump energy and therefore not needed to meet BHE's system load. Under this hypothetical scenario, BHE would not be avoiding any costs by taking the QF's energy since the energy is not needed to meet its system load, but the QF is still paid based on the market price forecast. Since the costs associated with the PPA would flow through the Fuel and Purchased Power Adjustment, BHE's customers would be paying for 100% of that QF's energy at a forecasted market price. BHE would then need to sell 100% of the QF's energy at the real-time market price since it is not needed to meet its system load. Differences between the real-time market price and forecasted market price could adversely impact BHE's customers based on tariff design.

BHE's avoided cost methodology which considers excess energy as dump energy for the Long-2 Case limits payment to only the energy that is used to meet its total system load. Without this, BHE's avoided cost methodology would not include any protections from a QF that seeks to have BHE purchase more energy than the it needs.

Q. How much of Fall River's energy is BHE's model predicting will be subject to the Long-2 Case?

A. Based on my calculations derived from the QF-in and QF-out models, the amount of dump energy attributable to Fall River is 15,944 MWhs. The following is a chart showing the amount of Fall River dump energy by year.



Q. Would the 15,944 MWhs of dump energy over the contract term have a material impact on the levelized avoided cost price?

A. No. Assuming the highest on-peak market price for each year is applied to all hours produced for that year, I calculate the net present value of dump energy over the PPA term to be $378,266. This equates to an impact on the levelized price of approximately $0.24/MWh. Keep in mind that this estimate is conservative because I assumed all dump energy modeled for a year was paid the highest hourly market price forecasted for that year. In reality, dump energy occurs during low loading hours when market price forecasts would likely be lower. Therefore, the differences between BHE's and Fall River's treatment of excess energy during the Long-2 Case is not a material driver of the avoided cost dispute in this case. My calculations are provided in Exhibit_DDK-5.

VII. <u>BHE and Fall River Avoided Cost Estimates</u>

Q. What is the levelized price BHE calculated for its avoided cost?

A. BHE calculated its avoided cost to be a levelized $28.30/MWh over the 20-year PPA term. This price includes avoided energy cost, avoided capacity cost, and avoided transmission costs.

Q. What is the levelized price Fall River calculated for BHE's avoided cost?

A. Fall River's witness Mark Klein calculates BHE's avoided cost as $48.76/MWh. However, Mr. Klein's analysis included generation from SD Sun I which BHE has since removed from the model. If Mr. Klein removed SD Sun I from the model, I would expect the avoided cost he would calculate to be slightly higher. This levelized avoided cost price includes energy, capacity, and transmission avoided costs.

Q. Why is there such a big difference between BHE's and Fall River's avoided cost prices?

A. There are two main reasons why the prices differ. The first reason is due to the Long-2 case, where BHE assigned excess Fall River energy as dump energy rather than assigning a forecasted market price. As discussed earlier in my testimony, I do not think this is a material driver of the price difference. The second reason, and the main driver for the price difference, is the payment for capacity to Fall River. The methods used by BHE and Fall River for calculating the avoided capacity costs are completely different.

A third possible reason could be the inputs (e.g. commodity price forecasts) Fall River used in its avoided cost model may differ from BHE's inputs. However, I did not investigate the differences between BHE's and Fall River's inputs since Fall River has not identified any issues with the inputs and assumptions BHE used (beyond the Long-2 Case) at the time of writing my testimony.[21]

VIII. Avoided Capacity Cost

Q. How did BHE calculate the avoided capacity cost?

A. Since BHE used the Differential Revenue Requirement method to determine its avoided cost, the modeling results include the cost of capacity. As the Planning and Risk model tries to balance generation to load, the model can choose new resource options to meet the forecasted demand for periods when BHE's existing resources cannot fulfill the forecasted demand. Typically, the costs and generating characteristics for the new resources are plugged into the model for a number of resource types and the model will choose the least-cost resource to meet the forecasted need over the planning horizon. The cost of the resource the model picks then gets incorporated into the total system cost of the model.

[21] Exhibit_DDK-7, Fall River's Responses to Staff DR 1-5 and 1-6.

Q. What new resource types did BHE include in its model?

A. It is my understanding that BHE only modeled one resource type to meet capacity deficiencies and that resource was firm energy purchases. BHE took the forecasted market price and then added a 20% premium to "firm up" the energy. This 20% premium is essentially the capacity payment.

Q. What concerns do you have with how BHE determined the avoided capacity cost?

A. First, I agree with BHE that the Differential Revenue Requirement method completed does include avoided cost for capacity and that cost is the 20% premium added to the forecasted market price for firm seasonal energy purchases. My main concern is that I have no way to verify that a 20% premium on market price is reflective of what capacity will cost in the later years of the model. BHE identified that the 20% premium is a practice used by its planning department when preparing IRPs and for internal budgeting purposes. I reviewed BHE's 2011 IRP and they did include firm market purchases in several scenarios, however I need to verify what premium they used.

I am also concerned that BHE did not include any other new resource types in its avoided cost modeling. While BHE does not have a large capacity need (discussed later in my testimony), I think smaller simple-cycle gas plants should have been an option for the model to pick. Through BHE's avoided cost calculation for Fall River, BHE is essentially telling the Commission that they will not build any new resources over the next 20 years. This could end up being the case, but at this time I find it difficult to believe and hard to verify, especially since more renewables (QF or otherwise) and distributed generation will likely be added to their system over the years which will likely require some form of additional balancing generation.

Finally, I have questions on how the model accounted for BHE's planning reserve margin. I do not fully understand how the load and resource balance (Exhibit AMT-2) was produced from the Planning and Risk model. The peak load identified in the Planning and Risk model does not appear to account for the planning reserve margin. If the model didn't account for the planning reserve margin, then the capacity value produced in the model would not represent the full value of Fall River's capacity.

Q. What was BHE's avoided capacity cost that was included in the levelized price?

A. BHE's witness, James McMahon, testified that the avoided capacity cost included in BHE's levelized price was $1.42/MWh. I think this number will change slightly since BHE re-ran its avoided cost models with the properly escalated market price forecasts. However, the number does provide an idea of what BHE determined its avoided capacity cost to be.

Q. How did Fall River calculate BHE's avoided capacity cost?

A. Fall River's witness, Mark Klein, used a method to determine BHE's avoided capacity cost that this Commission has not seen before. Essentially, Mr. Klein used SD Sun I as a proxy resource to determine the value of capacity. Since BHE purchased and planned to construct SD Sun I, Mr. Klein finds that SD Sun I is BHE's next resource that could be avoided by Fall River solar. Therefore, the value of SD Sun I's capacity over its lifetime is an appropriate proxy for the incremental value of capacity BHE will avoid due to Fall River.

In order to determine the value of capacity for SD Sun I, Mr. Klein calculated the levelized cost of constructing, owning, and operating SD Sun I over its expected 35-year lifetime using various assumptions based on his experience with other projects. That calculation identified a lifetime cost of power for SD Sun I of $53.35/MWh. Mr. Klein then ran the QF-in/QF-out Differential Revenue Requirement model using BHE's assumptions for SD Sun I to determine the avoided cost of energy for SD Sun I, which was $33.54/MWh. He then subtracted the $33.54/MWh from the $53.35/MWh to conclude that the value attributable to SD Sun I's capacity was $19.81/MWh.

Mr. Klein rationalizes that the value of capacity to BHE for SD Sun I is $19.81/MWh since the project would produce cost savings of $33.54/MWh and the only way BHE's investment can be considered prudent is if they had a need for capacity at that value.

Q. What concerns do you have with this method?

A. My first concern is the application of this approach. It appears that Mr. Klein is merging two forms of avoided cost methods. Those methods are the Proxy Price method and the Differential Revenue Requirement method. If the Differential Revenue Requirement modeling Mr. Klein completed used all of BHE's assumptions, then capacity is being double counted in his method since BHE modeled firm energy purchased at market price plus a 20% premium as a capacity resource.

My next concern is Mr. Klein's assumption that BHE needed to construct SD Sun I to meet a capacity deficit or energy shortfall. In this case, Mr. Klein assumes that the only way BHE's decision to purchase those projects, and then construct SD Sun I, can be prudent is if BHE had a need for capacity at the value proposed by Mr. Klein. I disagree with this assumption. Based on the modeling completed by BHE for the purchase decision, it appears the company was focused on reviewing the cost savings to its customers realized by owning the projects rather than flowing the cost of the QF PPA through the Fuel and Purchased Power Adjustment. Therefore, Mr. Klein's assumption that BHE had a need for capacity valued at $19.81/MWh is incorrect.

My third, and final concern, is the use of a solar resource as a proxy price for capacity. I understand Mr. Klein's argument that since BHE purchased the SD Sun I project and intended to construct it at the time of negotiations with Fall River then that would be the next resource avoided; however, I have not seen any resource modeling completed by BHE that demonstrates the SD Sun I purchase was the least cost resource to meet a forecasted capacity deficiency. Therefore, there is no demonstration that shows a solar resource is in fact the next resource to be avoided.

Q. What avoided capacity cost method is consistent with past Commission decision's?

A. Neither BHE's or Fall River's method directly aligns with this Commission's past decisions. However, BHE's proposed method is similar to the Commission's order in docket EL11-006.

In Order F-3365, the Commission found the following:

- The Commission finds that capacity credits included in long-term contracts should be based on the avoided cost of base load generation.
- The Commission finds that it is the addition of base load capacity which will most likely be affected by the capacity contribution of the QF under the long-term construct.

In its Amended Final Order in Docket EL11-006, the Commission found the following:

- The Commission finds that the proper avoided capacity costs are the $36 per kilowatt year avoided capacity costs value presented by NWE through the end-of-year 2015 termination date of NWE's capacity contract upon which this capacity value is based, and then escalating by 5.84 percent on January 1, 2016, and at the beginning of each year thereafter for the remainder of the 20-year QF contract term.

In its Final Decision in Docket EL16-021, the Commission found the following:

- The Commission further finds that the appropriate avoided capacity costs shall be based on the cost of a new simple cycle peaking plant.

For BHE's method, I noted that BHE's method is similar to the Commission's decision in docket EL11-006 because in that docket the Commission determined that short-term capacity contracts would be avoided and, therefore, the capacity contracts would set the avoided cost. However, the difference between that docket and BHE's method is that BHE is not basing its forecasted capacity price on a specific contract. In docket EL11-006 the Commission reviewed NorthWestern's most recent capacity contract and then escalated that contract at 5.84%, an escalation rate based on the Handy-Whitman index for the construction costs of natural gas turbo-generators, through the remainder of the PPA term after the capacity contract expired. Docket EL11-006 is different, in my opinion, because an actual capacity contract was used to set the initial price and escalated based on an index rather than BHE's proposed 20% premium to firm up seasonal energy purchases. Finally, I will note in docket EL16-021 the Commission considered establishing an avoided capacity cost based on short-term capacity contracts and rejected it.

Regarding Fall River's method, the Commission has not approved a similar method in the past. However, calculating avoided capacity costs outside of the Differential Revenue Requirement model is consistent with the Commission's past decisions. The Commission has not approved the use of the installed cost of a solar resource in the past as the next resource a utility will avoid. In docket F-3365 the Commission found that a baseload plant was the next resource a utility could avoid for long-term contracts and in docket EL16-021 the Commission found that a simple cycle gas plant would be the next resource the utility could avoid.

Q. What is your position on the proper method for determining avoided capacity costs?

A. At this time, I am inclined to take a position that the avoided capacity cost should be based on the cost of a simple cycle combustion turbine. In resource planning, the cost of new entry (CONE) of a simple cycle peaking plant is generally regarded as the avoided capacity cost. If the Commission agrees, BHE would need to remove the firm seasonal power purchases in order to remove the capacity value from their avoided cost price.

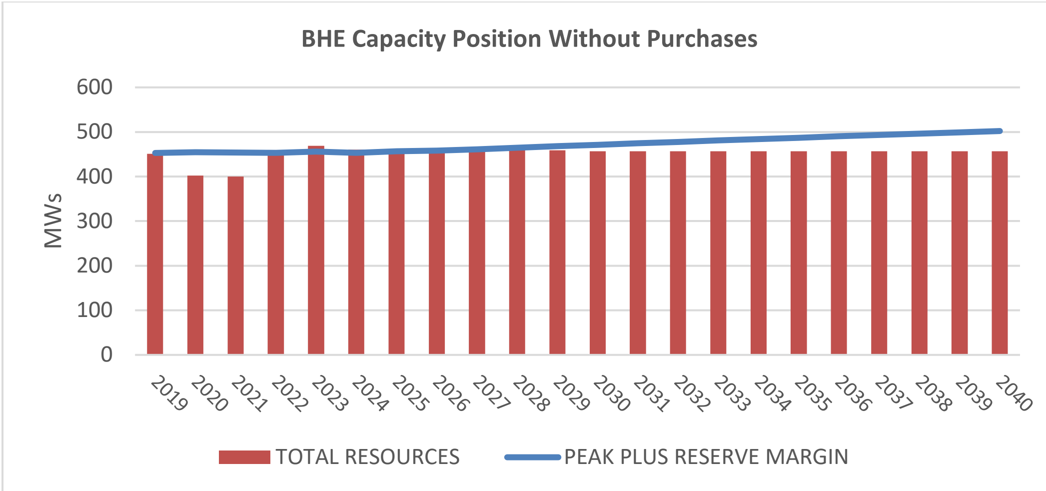
At this time, I cannot support BHE's proposed firm seasonal energy purchases as a capacity resource for a few reasons. First, I cannot verify the 20% premium is in fact the expected cost of reserving the capacity needed to produce the energy for the hours when BHE has a capacity deficit. Second, I am not entirely convinced that BHE will not construct, and seek cost recovery of, a new resource over the next 20 years.

I cannot support Fall River's avoided capacity cost method because I am not convinced that a solar resource is the next resource that BHE will need to construct. Based on my experience, a solar resource would not be the most cost-effective resource to meet the type of capacity deficit BHE is forecasting should BHE decide to address that deficit with a company-owned resource. I would expect a dispatchable resource would be needed to meet the capacity need.

Q. How much capacity should Fall River be compensated for?

A. This Commission[22] has determined that a QF should only be compensated for capacity that the utility can actually avoid. Given this, we need to look at BHE's capacity position over the PPA term. Below is BHE's capacity position after removing firm seasonal energy purchases as a proposed resource.

[22] Exhibit_DDK- 2, Docket F-3365 Order, Page 17 of 20.



As shown in the chart, BHE has a short-term capacity need in 2020 and 2021 and then becomes capacity adequate until 2027 when the capacity deficit begins to slowly increase with time. The table below provides the capacity sufficiency/deficiency BHE is forecasting by year. Negative numbers in the table indicate the capacity need.

BHE Capacity Position (MWs)

2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
-2	-52	-54	7	12	7	4	3	-1	-4	-9	-14	-18	-21	-24	-27	-30	-33	-36	-39	-42	-45

Based on the guidance from this Commission, it is my position that Fall River should be compensated for capacity based on BHE's annual forecasted capacity deficiency up to a maximum of Fall River's accredited capacity, beginning in 2021 (the first full year of Fall River generation).

Q. What was the accredited capacity factor used by BHE?

A. BHE used a 63% accredited capacity factor a solar resource. BHE's witness, Amanda Thames, justified the use of this accredited capacity factor by identifying it was used in the most recent IRP of an affiliate, Cheyenne Light, Fuel and Power Company.

Q. Do you agree with the use of a 63% accredited capacity factor for Fall River?

A. This is on the higher end of accredited capacity for a solar resource that I have seen. BHE's witness, James McMahon, made this same observation as well. Mr. McMahon provided accreditation factors used by two RTOs, PJM and MISO, as an example of this.

He testified that PJM's accreditation factor for solar resources was 47% in 2018 and MISO's accreditation factor for a new solar resource is 50%.

I will add that SPP's accreditation factor for a new solar facility is 10% for the first three years if a net capability calculation is not completed for that facility. After three years, SPP then requires a solar facility to perform the net capability calculation to determine the facility's specific capacity credit.[23]

Based on what the RTOs use as accredited capacity factors for solar facilities, I disagree with the use of the 63% accredited capacity factor for Fall River.

Q. What accredited capacity factor should be used for Fall River?

A. In my opinion, MISO's 50% accreditation factor for solar resources should be used if Fall River wants the total avoided capacity cost accounted for in a levelized price.

Q. Is there another method for determining accredited capacity you would support?

A. Yes. I would also support using a 50% accreditation factor for the first 3 years and then using actual Fall River generation data each year thereafter to perform a net capability calculation for the remainder of the PPA term. This method would provide a more accurate way of determining Fall River's accredited capacity. However, since the amount of Fall River's accredited capacity would not be known for every year, the total avoided capacity cost cannot be calculated at this time and, therefore, cannot be incorporated into a levelized price.

To implement this method, the Commission would establish a levelized price per kW-year (or kW-month) for capacity in this docket and then a capacity payment calculation would need to be performed periodically based on Fall River's accredited capacity determined from the net capability calculation. The terms of how often the capacity payment is calculated and how to perform the net capability calculation would need to be incorporated into the PPA. I refer to this as the SPP method.

[23] SPP Planning Criteria (Revision 1.9) - Section 7.1.6.1. Published on 6/20/19.

Q. Should the SPP method be used in this docket?

A. I am not recommending the use of the SPP method at this time. Given BHE's forecasted capacity deficit, an accredited capacity factor derived from the net capability calculation may only benefit the QF in years 2039 and 2040 as that is when BHE is forecasting a capacity deficit greater than 40 MWs.

Q. If the Commission adopts an accredited capacity factor of 50% or the SPP method, would this be discriminatory to Fall River?

A. In my opinion a 50% capacity credit, or use of the SPP Method, would not discriminate against Fall River. I understand BHE's justification for the use of a 63% accredited capacity factor was based on that factor being used in an IRP for its affiliate Cheyenne Light, Fuel and Power Company. BHE, however, has identified that it hasn't completed an IRP since 2011. Therefore, I don't think an affiliate's IRP is transferrable to BHE. In addition, Commission Staff was not able to review and challenge input assumptions used in Cheyenne Light, Fuel and Power Company's IRP during development.

Q. If the Commission adopts a 50% accredited capacity factor for Fall River and bases the avoided capacity price on the CONE for a simple-cycle combustion turbine, what would be the levelized capacity payment?

A. I calculated the levelized capacity payment to be $7.42/MWh.

Q. How did you calculate the capacity payment?

A. The main inputs into the cost calculation are BHE's annual capacity deficiency and the Cost of New Entry (CONE).

For determining the capacity deficiency, I used BHE's load and resource balance without Fall River and then subtracted seasonal firm energy purchases from the forecasted capacity position that accounted for a 15% reserve margin. It was necessary to subtract seasonal firm energy purchases because the model included the purchases as a resource to meet BHE's capacity deficiency.

For the CONE, I looked at the CONEs produced by MISO and SPP that were effective in 2018. According to MISO's annual filing[24] a CONE of $90.37/kW-year commenced on June 1, 2018. According to SPP's tariff[25] a CONE of $85.61/kW-year was effective on July 1, 2018. I averaged the two RTO CONEs for my capacity cost calculation, which was $87.99/kW-year.

I then escalated the $87.99/kW-year CONE estimate to 2021 using a 2.0% inflation rate, concluding that the 2021 CONE is $93.38/kW-year. I did this because the first year of avoided capacity costs will be in 2021. I then kept the CONE at $93.38/kW-year for the remaining PPA-term since the initial capacity is available in 2021 and that is the estimated cost of capacity at the time Fall River becomes operational.

Next, I calculated the annual capacity value by multiplying the CONE, after adjusting to $/MW-year, and BHE's capacity deficiency for each year up to a cap of 40 MWs. The 40 MW cap is Fall River's accredited capacity using the 50% accreditation factor. I then levelized that amount and divided by Fall River's levelized energy to determine the levelized capacity value of $7.42/MWh. My calculations are provided in Exhibit_DDK-6.

Q. Why is this levelized capacity payment higher than what the Commission approved in dockets EL16-021 and EL11-006?

A. Dockets EL16-021 and EL11-006 involved wind resources. Solar resources have higher accredited capacity factors than wind resources. As such, solar resources are compensated more for their capacity than wind resources and, as a result, one would expect a higher capacity payment for solar resources. In addition, docket EL11-006 used a capacity payment of $36/kW-year vs. the $93.38/kW-year I used in this docket.

Q. What would be the total avoided cost paid to Fall River for both energy and capacity based on your avoided capacity cost calculation?

A. I cannot provide an exact levelized price of BHE's avoided cost since BHE will need to re-run the model after removing the seasonal firm energy purchases. However, I

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[24] MISO 2017 Annual Cone Filing. Retrieved at: https://cdn.misoenergy.org/Final%20MISO%202017%20Annual%20CONE%20filing51321.pdf.

[25] SPP Open Access Transmission Tariff, Sixth Revised Volume No. 1 – Attachment AA Resource Adequacy, Section 13.

estimate BHE's levelized avoided cost price would end up near $34.30/MWh[26] with BHE's 1.5% inflation rate. If the inflation rate is increased, the final avoided cost price would increase as well.

IX. Interconnection and Network Upgrade Costs

Q. What are the interconnection and transmission network upgrade costs?

A. In response to discovery,[27] Fall River identified that the Feasibility Study and the System Impact Study reported the cost of interconnecting the Fall River project, as network resource, is $4,775,000 for the interconnection facilities and $335,000 for the network upgrades.

Q. Who is responsible for paying these costs?

A. Fall River identified that they are responsible for paying these costs.

Q. Are these costs contested in this case?

A. No. However, I am including this information in my testimony in order to provide my position on this matter.

Q. What is your position on interconnection and transmission network upgrade costs?

A. I agree with Fall River that they are responsible for both the interconnection and transmission network upgrade costs. The QF paying the interconnection facilities has not typically been an issue, however the funding of network upgrades was contested in docket EL16-021. As such, I felt compelled to provide a position on the recovery of network upgrade costs. If BHE ends up funding the network upgrades and includes those costs in rate base, then it would be my position that the avoided cost payment to Fall River should be reduced to cover that cost to rate payers.

[26] $28.30/MWh - $1.42/MWh (seasonal firm energy purchase adjustment) + $7.42/MWh = $34.30/MWh.
[27] Exhibit_DDK-7, Response to DR 1-11.

X. Renewable Energy Credits

Q. Are renewable energy credits at issue in this case?

A. No. Both Fall River and BHE are not including the value of renewable energy credits (RECs) in their proposed avoided cost price. Given this, it is my understanding that the ownership of the RECs would stay with Fall River. This is consistent with how the Commission ruled in dockets EL11-006 and EL16-021.

XI. Conclusion

Q. Please provide a summary of your testimony.

A. At this time, my position is as follows:

1) The LEO date should be September 6, 2018, as stipulated to. If the Commission adjudicates the LEO date, I believe a LEO was established on August 14, 2018.
2) BHE's use of the Planning and Risk model for conducting the Differential Revenue Requirement analysis is proper for determining its avoided cost and not discriminatory to Fall River.
3) BHE needs to better support its load forecast. This includes providing the method of the econometric forecast (i.e. identifying the variables considered and those ultimately used in the econometric model) and justifying the demand side management energy savings used in its energy forecast.
4) BHE's use of ABB's forecasts for market price and natural gas, after adjusting for inflation, is proper.
5) In my opinion, an inflation rate of 1.5% may be low. An inflation rate of 2% to 2.5% is typically used in resource planning. BHE needs to better support its inflation rate of 1.5% (e.g. historical look-back at an index).
6) I support how BHE modeled the Long-2 case and, in my opinion, it is consistent with PURPA, FERC guidance, and Commission precedent.
7) I determined that the Long-2 case at issue in this docket is not a material driver of the difference between Fall River's proposed avoided cost of $48.76/MWh and BHE's proposed avoided cost $28.30/MWh.
8) I determined that the avoided cost of capacity is the main driver of the difference between Fall River's and BHE's avoided cost estimates.

9) At this time, I disagree with both BHE's and Fall River's methods for determining avoided capacity costs. In my opinion, the avoided capacity cost should be based on the CONE for a simple-cycle combustion turbine and that Fall River should only be compensated for the capacity BHE actually avoids on an annual basis.

10) I disagree with the use of a 63% accredited capacity factor for Fall River and recommend using a 50% accredited capacity factor.

11) My calculation for the cost of capacity results in a levelized payment to Fall River of $7.42/MWh for capacity. If the Commission adopts my method for determining avoided capacity cost, BHE will need to re-run its avoided cost model to remove the seasonal firm energy purchases.

12) If the Commission adopts the avoided capacity cost of $7.42/MWh, it should be added to the avoided energy cost after BHE re-runs its model in order to determine the final avoided cost price that properly accounts for both energy and capacity.

13) I estimate BHE's avoided cost, including energy and capacity, at approximately $34.30/MWh using BHE's inflation rate of 1.5%.

14) I identified that interconnection costs and transmission network upgrades are not at issue in this docket and that Fall River acknowledged they are responsible for paying those costs.

15) I identified that ownership of the RECs will stay with Fall River.

Q. Does this conclude your testimony?

A. Yes, however, I reserve the right to supplement or amend my testimony should any new information come to light since depositions have yet to take place and discovery is still ongoing.