BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF SOUTH DAKOTA

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IN THE MATTER OF THE COMPLAINT OF ENERGY OF UTAH, LLC AND FALL RIVER SOLAR, LLC AGAINST BLACK HILLS POWER, INC.	:	
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DIRECT TESTIMONY AND EXHIBITS

OF MARK KLEIN

On Behalf of

ENERGY OF UTAH, LLC

AND

FALL RIVER SOLAR, LLC

February 11, 2019

Q: Please state your name, place of residence and occupation.

A: My name is Mark Klein. I live in San Diego, California. I am a consultant to the electric power industry. I own and operate a consulting company called Pacific Northwest Energy Consultants. I also am a partner in VK Energy, a company that develops and owns alternative energy generating facilities.

Q: How are you involved in this case?

A: I was retained by Energy of Utah and its subsidiary, Fall River Solar LLC, to consult on the economic value of energy and capacity produced by Fall River's proposed solar energy generating project near Oelrichs, in Fall River County, South Dakota, and to review and advise regarding Black Hills' calculation of avoided cost in this case.

Q: Please describe your education and employment background.

A: I hold bachelor and masters degrees in mechanical engineering. I've worked in the energy industries since 1985. I've worked exclusively in the electric industry in energy trading and rate related disciplines for a variety of utility and energy companies since 1995. In 2008 I formed Pacific Northwest Energy Consultants and have worked as a consultant in the electric industry since. My curriculum vitae is appended to my testimony.

Q: Have you consulted with public utilities that operate in South Dakota?

A: One utility you may be familiar with is Basin Electric Power Cooperative. Basin Electric Cooperative is a North Dakota based cooperative that generates electricity for 141 member cooperatives in nine states, including South Dakota. A few years ago, I performed detailed rate analysis and advised on tariff structures for Basin Electric and its member cooperatives.

Q: Have you testified as an expert witness?

A: During my employment with PacifiCorp and as an electric industry consultant, I’ve testified before the Utah, Wyoming, Oregon, and Montana public utilities/public service commissions on rate matters and related issues, including calculation of energy and capacity rates for solar energy generating facilities.

Q: Do you have experience with solar generating facilities?

A: In recent years I have been actively engaged in advising on the development of utility scale solar generation projects in Montana, Wyoming, Utah, and South Dakota, including performing resource modeling, evaluation of equipment and construction costs, and evaluation, calculation and forecasting the economic value of energy and capacity produced by the facilities.

Q: Do you consider yourself an expert on calculation of energy and capacity rates for solar energy generating facilities?

A: I do.

Q: What solar projects have you consulted on in South Dakota?

A: I was retained by Energy of Utah to consult on two solar generating projects in Fall River County near Hot Springs, called SDSun and SDSun II.[1] I participated in determining the economic feasibility of both projects, calculated rates for energy and capacity produced by the projects, and advised on elements of the power purchase agreements pertaining to the sale of energy and capacity to be produced by the projects.

Q: Describe those projects.

[1] The projects were owned by two subsidiaries of Energy of Utah, SDSun LLC and SDSun II LLC. For convenience I’ll call the projects SDSun I and II in my testimony.

A: In 2016, Energy of Utah's subsidiary SDSun proposed constructing two solar generating facilities totaling 40 megawatts nameplate capacity west of Hot Springs near Black Hills Corporation's Minnekahta substation, less than 25 miles northwest of the proposed Fall River facility. The company designed and completed the engineering for the construction of the two solar facilities. SDSun I and II were both certified as Qualified Facilities (QF) under the federal Public Utilities Regulatory Policies Act of 1978 (PURPA) with the Federal Energy Regulatory Commission (FERC). Both projects were located in Black Hills Corporation's exclusive service territory. SDSun I and II proposed to interconnect with Black Hills' electric transmission system at the Minnekahta substation. SDSun I and II requested Black Hills recognize their QF status and determine a rate Black Hills would pay for the electricity the facilities produce and the capacity they provide, a so-called "avoided cost" rate. After some negotiation, in 2016 Black Hills and SDSun I entered into a power purchase agreement in which Black Hills agreed to buy the energy and capacity generated by the facility for twenty-five years at a levelized cost of $44.54 per megawatt hour of generation.

Q: What is the current status of SDSun I and II?

A: Energy of Utah sold both SDSun I and II to Hanwha Q Cell and its US subsidiary Global Power 174 in late 2016. Black Hills entered into a power purchase agreement with SDSun II in 2017 at an avoided cost rate slightly lower than the rate negotiated for SDSun I. Black Hills subsequently purchased all rights to both projects from Hanwha and Global 174 and has indicated its intention to construct SDSun I, a 20-megawatt facility, this year.

Q: How are those projects relevant to the issues in this case?

A: The SDSun I and II are relevant to this case at several levels. First, they are geographically close to the Fall River facility. All three projects are essentially at the same latitude, meaning their exposure to the sun is the same. Second, they all have QF status. Third, their design is similar. Fourth, all three projects will provide energy and capacity to the same utility, Black Hills. Fifth, little has changed in Black Hills' generation fleet or in area electricity demand since the SDSun I and II power purchase agreements were signed. Finally, Black Hills has advised Fall River at various times that it intends to construct both projects, and most recently, SDSun I in 2019 and include it as an owned asset in its generation fleet.

Q: In earlier testimony you described the Fall River facility as having "QF status." Explain to the Commission the significance of QF status.

A: In 1978, Congress passed PURPA, partially in response to the then perceived energy crisis. PURPA encouraged the generation of electricity from small scale domestic renewable resources owned by independent power producers. Wind and solar generation are examples. PURPA requires that Black Hills offer to purchase electric energy and capacity generated by QFs within its service territory. If a generator meets certain PURPA criteria, it is called a *qualified small power production facility*, or QF.

Q: What are the criteria a generator must meet to become a QF?

A: Generally speaking, the facility must generate electricity from a renewable resource, its capacity to generate electricity must be 80 megawatts or less, and if its capacity is more than 20 megawatts, it must not have access to an organized wholesale market for the sale of electric energy, ancillary services, and capacity.

Q: Does the Fall River facility meet those criteria?

A: The Fall River facility meets the criteria for QF status. Its generation is from a renewable resource, the sun. Its capacity to generate electricity won't exceed 80 megawatts. Black Hills' service territory is not located within the footprint of an organized wholesale market for the sale of electric energy, ancillary services and capacity, and Black Hills does not have transmission or interconnection services that provide access to such a market.

Q: Has Fall River attained QF status?

A: Yes, in early 2018 Fall River certified its QF status to FERC.

Q: Why is QF status important to the owner of small renewable energy generator like Fall River?

A: In Fall River's case, when it achieved QF status, it could lawfully request Black Hills to calculate the rate it will pay for the energy and capacity generated by Fall River's facility. Once an acceptable rate is determined, Black Hills must, per PURPA, enter into an agreement with Fall River to purchase the energy and capacity it produces.

Q: What is that rate called?

A: The rate paid to the QF is commonly called an *avoided cost rate*.

Q: Why is it called an avoided cost rate?

A: Because Black Hills won't be building the new Fall River generator, Black Hills won't incur the cost of construction, ownership and operation of Fall River's 80-megawatt generator. It *avoids* those expenses. But Black Hills will receive the electricity and capacity Fall River generates and per federal law must pay for it. What Black Hills must pay Fall River for the energy and capacity it generates is determined from the costs Black

Hills avoids. Hence the name *avoided cost rate.* The rate is expressed in dollars per megawatt hour of generation.

Q: Is the rate the same over Fall River's life?

A: No, the rate varies from year to year due to changes in Black Hills' sources of generation, demand for electricity and costs in generating electricity. Typically, the rate a utility must pay is "levelized," meaning that it is mathematically reduced to a rate that is a constant over the life of the contract between the utility and the QF. As explained later in my testimony, the life of the contract between Fall River and Black Hills will be twenty years. The levelized avoided cost rate is the price Black Hills must pay Fall River for each megawatt of electricity and capacity Fall River produces over that twenty years.

Q: You include *capacity* in the rate. What is capacity and why does it have value?

A: Every utility must assure that it has the capacity to generate electricity sufficient to meet its customer's demand for electricity. Federal and state law require the utility to have a reserve of capacity greater than its customer's highest or peak hourly demand. The ability to meet peak demand is called *capacity* and it has an economic value that can be calculated.

Q: Are there legal restrictions on the avoided cost rate?

A: Federal law requires Black Hills must calculate a rate that is fair and reasonable to Black Hills' customers but does not discriminate against Fall River.

Q: Explain the term *legally enforceable obligation* in the sense used by PURPA and FERC regulations.

A: The Legally Enforceable Obligation concept's genesis is in a FERC regulation that addresses avoided cost pricing. A Legally Enforceable Obligation (LEO) is formed when a QF unequivocally commits to sell all the energy and capacity it generates from its facility to a utility on an exclusive basis. An LEO can be formed unilaterally by a QF making the commitment to sell all its energy and capacity exclusively to the utility.

Q: What choices does a QF have in the formation of an LEO?

A: The QF can choose, under FERC regulations, to be paid the avoided cost rate at the time it delivers energy to the utility or, alternatively, at a rate spread over a specified time period beginning at the time the LEO is formed. If the QF chooses to have the avoided cost calculated over time for a specified period, and most do, the utility must estimate avoided cost over the term of the proposed contract.

Q: Which election did Fall River make?

A: Fall River elected to have avoided cost calculated over a period of 20 years.

Q: Why is an LEO date important?

A: The date an LEO is formed is the point in time from which a QF is entitled to have its avoided cost rate determined.

Q: How is an avoided cost rate determined?

A: PURPA and FERC regulations define avoided cost as

> "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility . . . such utility would generate itself or purchase from another source."

To calculate an appropriate avoided cost rate, Black Hills must, in some manner, hypothesize the costs it will avoid over the next 20 years by purchasing the electricity and capacity generated by Fall River's facility. To make that calculation Black Hills must project its anticipated generating resources, the volume of generation from those resources, costs of generating electricity, and its customer's demand for energy for the next 20 years, including what additional resources are required to meet anticipated energy and capacity needs.

Q: Are economic forecasts important to calculating avoided cost?

A: Economic forecasts are at the heart of avoided cost calculations that involve a term of years. A variety of economic forecasters project economic conditions in the future. Black Hills relied on projections made by Ventyx, an economic forecasting company that supplies projections to electric industry. Black Hills used a Ventyx forecast called the Ventyx North American Power Reference case. It is published twice a year, called the Spring Reference Case and the Fall Reference Case. The Ventyx North American Power Reference Case is an analysis of the North American electricity market that supports forward-looking modeling of power, gas, coal and environmental markets. The Ventyx reference case makes 25-year forecasts based on a variety of economic assumptions for various areas of the country, including Black Hills' service territory.

Q: Is the date on which the forecast is made important to an avoided cost calculation?

A: The date of the forecast is important relative to the LEO date. Avoided cost must be calculated in close time proximity to the LEO date per prior orders of the South Dakota Public Utilities Commission. Accordingly, the forecast must be proximate in time to the LEO date.

Q: Has an LEO date been established in this case?

A: An LEO date of September 6, 2018, has been established.

Q: What facts support a September 6, 2018, LEO date?

A: Fall River requested Black Hills provide an avoided cost rate for its project in early 2018. After an exchange of rate estimates between Fall River and Black Hills, in June 2018 Fall River tendered a draft power purchase agreement to Black Hills. The draft was essentially identical to the power purchase agreements negotiated between SDSun I and Black Hills two years earlier. On August 14, 2018, Fall River advised Black Hills that it believed the levelized avoided cost rate should be $41.66 per megawatt hour, based on Black Hills' earlier indication that it intended to build both SDSun I and II and employ them as part of its generator fleet for purposes of calculating avoided cost. On August 29, 2018, Black Hills proposed a recalculated avoided cost rate, employing the 2018 Spring Ventyx North American Power Reference case forecast and incorporating only SDSun I in its generation fleet. Fall River declined the proposed rate by letter on September 6, 2018, and advised that the parties were at an impasse. Although Fall River believes a case can be made that an LEO was formed as early as June, Black Hills, the PUC staff, and Fall River have agreed that September 6, 2018, is the date a legally enforceable obligation was created.

Q: What avoided cost rates did Black Hills propose?

A: On April 27, 2018, Black Hills proposed to pay Fall River the 20 year levelized rate of $17.06 per megawatt hour for capacity and energy produced by the Fall River solar generator. On August 29, 2018, Black Hills proposed a recalculated levelized avoided cost rate of $21.70 per megawatt hour for the capacity and energy produced by Fall River's solar generator, levelized over 20 years.

Q: Do you know how Black Hills calculated avoided cost?

A: Black Hills calculated avoided cost using a form of the *differential revenue requirement* method. The differential revenue requirements method, or DRR, calculates the difference in Black Hills' revenue over a 20-year term with and without Fall River's energy and capacity. During certain periods, Black Hills allowed no payment for energy and capacity generated by Fall River.

Q: Were there any significant differences between the April and August approaches that Black Hills used?

A: Black Hills employed the 2017 Fall Ventyx North American Power Reference case forecast in its April calculations and the 2018 Spring Reference case in its August 2018 calculations. In the April calculation, Black Hills included 52 megawatts of solar generation. The generators were identified as SDSun I and II, totaling 40 megawatts, and an additional 12 megawatts of solar generation. In the August calculation, Black Hills only included 20 megawatts of solar generation from SDSun I. Black Hills did not include the 20 megawatts from SDSun II and the additional 12 megawatts of solar generation.

Q: In your opinion, is the avoided cost calculated by Black Hills on August 29th an accurate determination of the costs it will avoid over 20 years as a result of Fall River's generation?

A: No. Black Hills' calculation of avoided cost is incorrect in two significant respects.

Q: In what way is the calculation incorrect?

A: First, Black Hills did not include any allowance for the value of capacity in its calculations, despite the requirement in federal law that an avoided cost calculation should include ". . . the incremental costs . . . of electric energy or capacity or both . . ."

Black Hills should have taken into account the cost for construction, ownership, and operation of SDSun I as the foundation for calculating the value of capacity, and then added an allowance for capacity to its avoided cost.

Q: What is the basis for your assertion that costs associated with SDSun I should be used to determine the value of capacity?

A: Black Hills has committed to SDSun I being its next generator. SDSun I is a 20 megawatt solar generator, originally developed by the same party developing Fall River, to be constructed in time proximity to the construction of Fall River's facility, located less than twenty-five miles away. Accordingly, the most accurate reflection of the incremental cost of capacity Black Hills will avoid by purchasing Fall River's energy and capacity is the value of capacity produced by SDSun I.

Q: What other error did Black Hills make in its calculation?

A: In its calculation of avoided cost, Black Hills excluded payment to Fall River during those periods when Black Hills could not reduce its generation to match its customer demand, so-called "long" situations.

Q: Why is that inappropriate?

A: According to public information, Black Hills has contractual arrangements to sell all of the electricity that it generates when it is in a long situation. Black Hills realizes income from the sale of that energy.

In its calculation of avoided cost, Black Hills employed forward looking forecasts for demand and energy costs. Its forecasts take into account periods when it is short of energy, periods when it has more energy available than required to meet demand, but can reduce its generation to match demand, and periods when it has more energy available than required to meet demand but cannot reduce its generation to match demand, the so-called Long 2 situations.

Publicly available information demonstrates that Black Hills, even though not situated in an organized electrical market, sells all its extra energy when it is in the Long 2 situation through bi-lateral agreements with other utilities. Thus, Black Hills realizes an income from that energy, even though the energy isn't used to supply Black Hills customers. Even so, when it is in a Long 2 situation, Black Hills' avoided cost rate does not include any payment to Fall River.

PURPA requires that avoided cost rates must be just and reasonable to Black Hills customers and in the public interest, but at the same time not discriminate against Fall River. Determination of reasonableness versus discrimination has been described as "customer indifference," meaning that the avoided cost rate must result in no impact on Black Hills customers. If Black Hills sells energy produced by Fall River to other utilities pursuant to bi-lateral contracts, but pays Fall River nothing for the energy, the revenue from the sales benefits either Black Hills customers or shareholders, which clearly is not "customer indifferent" and is inherently discriminatory against Fall River. Black Hills gets the benefit of Fall River's investment without paying for it. Black Hills' avoided cost rate should include payment to Fall River during Black Hills' long situations.

Q: Has FERC addressed the issue of long situations in relation to calculating avoided cost?

A: To my knowledge FERC has not directly addressed the issue. Northwestern Corporation recently filed a petition with FERC asking for a declaratory ruling on the issue as a result of the Montana Public Service Commission's rulings requiring Northwestern to pay QFs for their generation when Northwestern is in Long 2 situations.

Q: Have you calculated what you believe to be the Black Hills' avoided cost for the Fall River facility?

A: Yes. I believe a more accurate assessment of avoided cost, levelized over 20 years to be $48.76 per megawatt hour.

Q: How did you calculate that rate?

A: Black Hills told Fall River that it intended to construct SDSun I in 2019 and included it in its generation fleet when it calculated avoided cost. Because SDSun I will be Black Hills' next generation resource and because Black Hills says it will begin commercial operation in close time proximity to the construction of Fall River, the value of its capacity over its life is an appropriate proxy for the incremental value of capacity Black Hills will avoid by purchasing Fall River's generation and capacity.

I calculated SDSun I's levelized cost of construction, ownership and operation spread over its expected 35-year life. I have recently been involved in evaluating equipment, construction and operational costs for several solar generation projects in the Rocky Mountain region. Because I don't know exactly what Black Hills spent to acquire SDSun I or what it forecasts for construction, equipment and operational costs, I developed an estimate of the cost of constructing, financing, operating and maintaining the facility, extrapolated from my recent work, with allowances for local land related costs.

Table 1 below shows my estimate of capital expense and operating costs for SDSun I, using relatively current cost estimates.

Table 1:

Cost Element		Nominal $
Capex	**$/Wdc[2]**	
Interconnection		(715,000)
Collector Substation		(2,485,000)
Panels ($/Wdc)	$0.35	(8,400,000)
Tracker ($/Wdc)	$0.11	(2,640,000)
Inverters ($/Wdc)	$0.04	(840,000)
Balance of Plant	$0.40	(9,600,000)
Capex Subtotal		**(24,680,000)**
Development Cost		
Interconnection Study		(16,000)
Engineering		(25,000)
Legal		(25,000)
Permitting		(25,000)
Development Subtotal		**(91,000)**
Operating Costs (35 years)		
O&M		(3,425,280)
Insurance		(1,696,320)
Land Lease		(1,214,489)

[2] Wdc means watts, direct current. Note that the direct current produced by the solar generator must be converted to alternating current before it is transmitted, with some correspondent loss of energy.

Property Tax		(18,671,272)
Operating Cost Subtotal		**(25,007,360)**

Q: Did you make any assumptions regarding lifetime costs of the project?

A: Yes, Table 2 below shows the assumptions I made:

Table 2:

SD1 Solar Lifetime Cost Assumptions	
Size (MWdc)	24
Size (MWac)	20
Annual Generation (MWh)	43,441
Annual Degradation	0.50%
Project Life (Years)	35
Federal Tax Rate	21.00%
ITC[3]	30.00%
Black Hills Power (WACC)[4]	7.41%

Q: Once you completed your cost and operational analysis and formulated your assumptions, what did you do?

A: I calculated the levelized cost over 35 years for each category of cost and expense applicable to SDSun I. I used Black Hills' weighted cost of capital of 7.41% as the discount rate to levelize the costs. The outcome of my calculation is expressed in dollars per megawatt hour. Table 3 below shows the outcome of that calculation.

[3] ITC means investment tax credit.
[4] WACC means Weighted Average Cost of Capital.

Table 3:

Levelized SD1 Costs (2021) $/MWh	
Levelized Capex Costs	($48.29)
Levelized Development Costs	($0.21)
Levelized Operating Costs	($17.16)
ITC Benefit	$14.54
Depreciation and Taxes	($2.23)
Levelized SD1 Lifetime Cost of Power	($53.35)

Q: What conclusion did you reach?

A: Over the 35-five-year life of the SDSun I the levelized cost of generation from the facility will be $53.35 per megawatt hour.

Q: What did you do next in your calculations?

A: Next I prepared three models. To assure that my calculations and Black Hills' calculations were based on the same data, I used the 2018 Spring Ventyx North American Power Reference case forecast and modeling information that Black Hills provided to Fall River in conjunction with its August avoided cost calculation.

Q: Describe the models you prepared.

A: In my first model I removed SDSun I from Black Hills' generation fleet to determine Black Hills' revenue requirements without SDSun I.

Q: What was the purpose of preparing the first model?

A: I needed a base line to use as I calculated the economic contributions that SDSun I and Fall River would make to Black Hills and prepared the other models.

Q: What was the second model that you prepared?

A: My second model included the generation SDSun I will contribute to Black Hills and associated revenue requirement reduction, as if it were a QF. The difference in outcome between my first model and my second model is SDSun I's hypothetical avoided cost. The model is essentially the same form of the differential revenue requirement method of calculating avoided cost Black Hills used to calculate Fall River's avoided cost, except it calculates SDSun I's avoided cost.

Q: What was the outcome?

A: The model determined that if SDSun I was a QF, its levelized avoided cost over 20 years, using the same Ventyx data and modeling Black Hills used, is $33.54 per megawatt hour of energy produced. It is important to note that $33.54 is the avoided cost for *energy only* and does not include any value for capacity.

Q: What was the purpose of preparing the second model?

A: I wanted to determine the value of the avoided cost of energy for SDSun I, first to understand its impact on Black Hills' system, and second to lay the foundation for determining the value to Black Hills of SDSun I's capacity to produce electricity.

Q: What was the third model you prepared?

A: My third model included the revenue both SDSun I and Fall River will contribute to Black Hills' revenue stream, as if both were QFs. Again, I used the same data and modeling Black Hills used.

Q: What was the outcome of the third model?

A: The third model determined that the levelized avoided cost of energy for Fall River after including SDSun I in Black Hills' generating fleet is $28.95 per megawatt hour. It is important to remember that $28.95 does not include the value of Fall River's contribution to capacity.

Q: How is the Long 2 situation treated in your calculations?

A: When Black Hills is in the Long 2 situation, my calculated levelized avoided cost of $28.95 per megawatt hour reflects the revenue Black Hills receives from sale of Fall River's generation to other utilities.

Q: Did you calculate a value for Fall River's contribution to Black Hills' capacity?

A: In my evaluation of SDSun I described above, I calculated its levelized cost of ownership and operation as $53.35 per megawatt hour of generation. As described above, I determined SDSun I's levelized revenue from energy was $33.54 per megawatt hour. If it costs Black Hills $53.35 per megawatt hour to own and operate SDSun I, and the revenue SDSun I will produce is $33.54 per megawatt hour, the only way Black Hills' investment in SDSun I can be considered prudent is if the difference between cost and revenue is value attributable to capacity. If not, Black Hills cannot justify the construction of SDSun I. The difference between cost and revenue, per the models I prepared using Black Hills' information, is $19.81 per megawatt hour.

If the capacity of SDSun I is valued at $19.81 per megawatt hour, the capacity of Fall River, an essentially identical project, must also be valued at $19.81 per megawatt hour.

Q: If you add $19.81 per megawatt hour, what is Fall River's final avoided cost?

A: The third model I ran calculated Fall River's 20-year levelized avoided cost at $28.95 per megawatt hour for energy. Adding capacity at $19.81 means Fall River's total avoided cost is $48.76 per megawatt hour.

Q: In your opinion, is $48.76 per megawatt hour Black Hills' avoided cost?

A: Yes.

Q: Did you prepare a report that contains the details of your calculations?

A: Yes, a copy is attached as Exhibit A.

Q: Is the testimony your final analysis and opinion with regard to avoided cost in this case?

A: No, before I can give a final opinion on an appropriate avoided cost in this case, I must have additional information that will be developed by discovery.

Q: Why do you need additional information?

A: Primarily to confirm my calculations are correct and to support and confirm the assumptions I made in my calculations. Secondarily, to understand if the avoided cost calculations that Black Hills prepared in April and August were based on accurate information and appropriate assumptions.

Q: What additional information do you need?

A: As mentioned above, I developed the cost of construction, operation and ownership of SDSun I from recent work I did evaluating construction and operational costs for solar facilities being developed in the Rocky Mountain region. Through discovery, I need to learn Black Hills' acquisition costs for the SDSun I project, Black Hills' anticipated costs for materials and construction of the facility including costs for modification of the Minnekahta sub-station, land costs, and any other costs and expenses Black Hills anticipates incurring bringing the project to commercial operation. I also need to learn Black Hills' budgeting for operation of the completed facility over time. Finally, I need to learn Black Hills' expectations for the production of electric energy from the facility. When I have that information and have had an opportunity to test its accuracy, I can refine my avoided cost calculation using Black Hills' expected investment and return from the facility.

In order to completely critique Black Hills' calculation of avoided cost I need to know considerably more detail about Black Hills' modeling and the assumptions Black Hills made in conjunction with its computations. Developing that information will require discovery. Once I have that information, I will be able to more definitively comment on Black Hills' methodology and calculations. That information may also affect my calculations.

I need to know more about how Black Hills values assets for rate making purposes, which will also require discovery. Once I have that information, I will be able to more definitively comment on Black Hills' approach to the long situations.

I need a more complete understanding of Black Hills' bi-lateral contracts for the purchase and sale of electricity and capacity.

I need to be satisfied that Black Hills can actually construct SDSun I in the timeline it reports. If it unable to construct the project in the timeline reported, avoided cost will change.

Q: Do you expect to file additional direct testimony when you have that information?

A: I cannot be certain whether I will need to submit additional direct testimony to clarify and supplement the opinions presented in this testimony until I have seen the additional information and reviewed the testimony of Black Hills regarding its methods of computation of avoided cost. Practically speaking, I think it is likely I will have to amend or supplement this testimony. Accordingly, I reserve the right to supplement, amend or modify the conclusions and opinions I have expressed in this testimony.